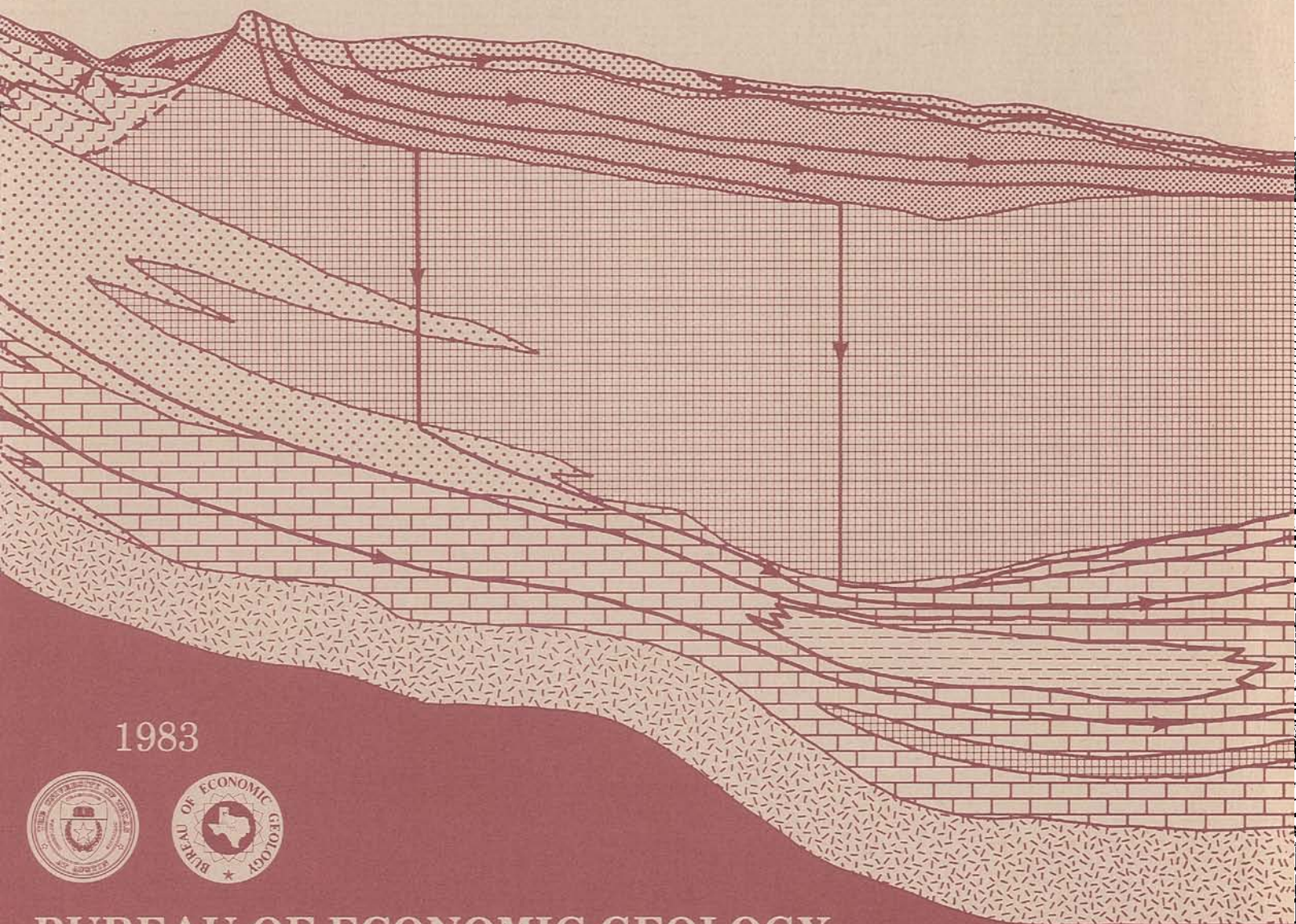


Report of Investigations No. 130

Deep Brine Aquifers in the Palo Duro Basin: Regional Flow and Geochemical Constraints

by
R. L. Bassett and M. E. Bentley



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BUREAU OF ECONOMIC GEOLOGY

W. L. Fisher, Director

The University of Texas at Austin

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assisted by
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ABSTRACT

Geologic characterization of evaporite deposits as potential host rocks for burial of radioactive waste must include hydrogeologic investigations at both local and regional scales. The Palo Duro and Dalhart Basins of Texas contain candidate salt deposits that are underlain by shelf carbonates and fan-delta sandstones. These basins are ancient intracratonic elements exhibiting regional eastward flow in the deep brine aquifers. Pressures in these aquifers are "subnormal"; however, the major component of flow appears to be parallel to bedding, owing to the low permeability of the overlying evaporite strata in the central part of the basin.

Salinity values computed from geophysical logs or obtained from chemical analyses indicate only small aberrations from a regional average salinity for brines in carbonate rocks and sandstones of Late Pennsylvanian and Early Permian age. Brine composition is derived by reaction with the host rock, obtaining salinity primarily from evaporite facies and, at present, apparently follows the calcite phase boundary. Brines may also be near equilibrium with anhydrite except in regions where sulfate reduction has generated hydrogen sulfide. Evidence of ion exchange is tenuous; however, clastic sediments predominate in the western part of the basin, early in the flow path, and a significant reduction in the molar ratio of sodium to chloride is observed in many samples. Substantial outgassing of carbon dioxide (CO_2) and oxidation of ferrous iron appear to have occurred as the samples were collected by industry during wildcat drilling. Mass transfer computer programs have been used to determine the most probable in situ brine composition. Support for the validity of the computed equilibrium state is the correlation between the values of partial pressure of carbon dioxide (P_{CO_2}) calculated for the brines and the P_{CO_2} observed in adjacent natural gas reservoirs.

Keywords: aquifers, computer modeling, drill-stem-test analysis, Early Permian, geochemistry, hydrogeology, Late Pennsylvanian, nuclear waste, Palo Duro Basin, Permian Basin, Texas

INTRODUCTION

Locating and characterizing geologic sites for burial of high-level commercial radioactive waste entails a multidisciplinary approach. The Bureau of Economic Geology (BEG) of The University of Texas at Austin is responsible for investigating all aspects of the geology and hydrology of the Palo Duro and Dalhart Basins of Texas. The results will be used by the U.S. Department of Energy (DOE) to determine if these basins are suitable for disposal of nuclear waste in Permian salt formations. Predictions of the long-term behavior of a mined geologic nuclear waste repository will be based on knowledge of the ground-water hydrology of the environment surrounding the proposed site. Transportation by ground water is by far the most likely mechanism by which radionuclides could reach the biosphere from an

underground repository. The physical and hydrologic framework of the region is established by integrating the results of studies in stratigraphy, structure, economic resources, surface processes, geochemistry, and hydrology.

Recently the hydrogeology of deep, saline aquifers has received increased attention from researchers investigating a variety of topics, including petroleum migration and entrapment, disposal of liquid wastes, desalinization, origins of oil field brines, and regional fluid flow. Consequently, a number of benchmark papers describe regional hydrogeologic systems, such as the investigation of the San Juan Basin (Berry, 1958), the Permian Basin (McNeal, 1965), the Paradox Basin (Hanshaw and Hill, 1969), the Western Canada sedimentary basin (Hitchon, 1969a, b; Hitchon and Hayes, 1971; Tóth, 1978), the Australian Surat Basin (Hitchon and Hayes, 1971), and the Illinois Basin (Bond, 1972).

Geochemical studies such as those by Hitchon (1963a, b, c), White (1965), Clayton and others (1966), Rittenhouse (1967), Carpenter and Miller (1969), Collins (1975), and Carpenter (1978) have been pivotal in describing water/rock interactions in deep formation brines.

Emerging from many of these studies is the concept that the potential distribution, and therefore flow, in mature compacted basins may be significantly determined by the surface topography and resultant configuration of the top of the saturated zone (Tóth, 1978). This conclusion indicates that strata usually considered to be impermeable may actually permit vertical and cross-formational flow sufficient to transmit fluid pressure from shallow to much deeper flow systems. These studies also suggest that brines are actively reacting with host rocks in sedimentary basins. Depending on the nature of the basin fill (for example, whether the fill is evaporite, carbonate, or clastic), the host rock actively modifies the composition of the brine as it moves along the flow path.

Hydrologic interpretation of the Palo Duro and Dalhart Basins is limited by the same constraints that qualify these basins as potential repository sites, specifically, the low well density and the low resource potential. Petroleum exploration activities provide the primary, if not the exclusive, source of pressure measurements for the deep aquifers, as well as the chemical determinations of formation brines.

Exploration for hydrocarbons in the Palo Duro and Dalhart Basins historically has been nonproductive; consequently, the amount of subsurface data is severely limited. Hydrologic conclusions are drawn both from wildcat well data available for the basins of interest and from information obtained from the basin margins and adjacent basins that are petroliferous. This report describes the first phases in a regional study of deep ground-water hydraulics and dominant geological constraints on brine compositions. Particular emphasis is placed on the Wolfcamp carbonate aquifers of Early Permian age. Information derived from these and other geological investigations is being further refined with data from additional drilling and will be presented elsewhere (Bassett and Bentley, in press). Nevertheless, preliminary characterization is needed now to evaluate these basins as

candidates for waste isolation. The Palo Duro Basin is the focus of this investigation. Detailed discussion of the Dalhart Basin is deferred owing to the sparse data base and the fact that the hydrogeology of the two basins can be treated independently.

HYDROGEOLOGIC FRAMEWORK

The Palo Duro and Dalhart Basins are shallow intracratonic basins, two of the several subbasins composing the larger Permian Basin. The Palo Duro Basin is asymmetrical; the greatest thickness of sediment (about 10,000 ft [3,050 m]) occurs just north of the Matador Arch (fig. 1). The extreme hydrologic inhomogeneity of the basins results from long-lived cycles of different styles of sedimentation. Relatively permeable formations are vertically separated by a thick interval of middle and Upper Permian evaporites and fine-grained red beds that effectively divides the sedimentary sequence into deep and shallow flow systems.

The relation between stratigraphic and hydrogeologic divisions (Tóth, 1978) is shown in table 1. The hydrogeologic elements were designated according to their relative water-conducting or water-retarding character. Several of the hydrogeologic elements are composed of generally permeable lithologies (sandstone, dolomite) interbedded with mudstone; in this case the appellation of "aquifer" or "aquitard" was based on the properties of the more permeable strata. For this report, hydrogeologic units (table 1) are composed of one or more of the hydrogeologic elements. Thus, the units represent assemblages of vertically contiguous strata that have different primary lithologies but the same general hydraulic properties. The permeabilities shown in table 1 are representative values derived from the literature or determined in this study by analysis of drill-stem tests.

The apparent upper stratigraphic limit of the deep-basin brine aquifers coincides with the top of the Wolfcamp (Lower Permian) dolomite (table 1). Most of the pre-Leonardian deep-basin brine aquifer is composed of open-marine platform carbonates and fluvial-deltaic arkosic sandstones

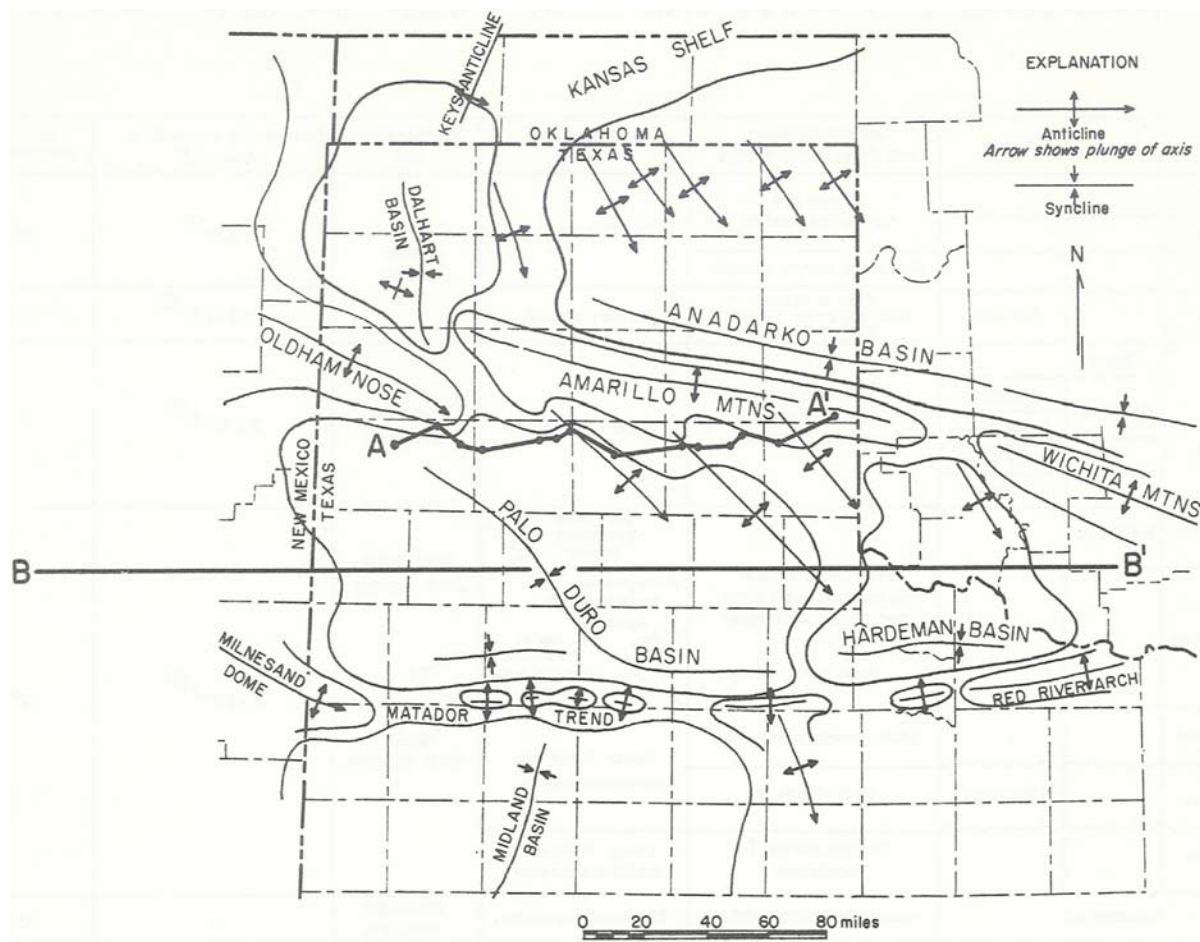


Figure 1. Location of study area and cross sections (see figs. 5 and 8). Structural elements of the Texas Panhandle from Nicholson (1960).

(granite wash) interbedded with mudstone. No major lithic change marks the Pennsylvanian-Permian boundary; throughout this time the nature and location of different depositional environments was strongly influenced by syndepositional tectonism that was actively shaping the basin. The distribution of sandstone aquifers was controlled by erosion of faulted granitic and gabbroic Precambrian basement highlands that formed the basin boundaries (figs. 1 and 2). Fan-delta sandstones emanate from major sediment-source areas such as the Amarillo Uplift to the north and the Oldham Nose and Sierra Grande Uplift to the northwest (figs. 1 and 3). Other deltaic deposits extend into the basin from the northeast; those were supplied by sediments eroded in the Wichita Mountains of

Oklahoma (Handford and Dutton, 1980). Basinward from these peripheral sandstones and intertonguing with them are shelf carbonates that themselves grade basinward into thicker, more vertically persistent shelf-edge carbonate buildups that bordered the central basin (figs. 2 and 4). As subsidence diminished in late Wolfcamp time, shelf-margin carbonates had prograded across the mud-filled central basin to form a basinwide shelf-carbonate system (fig. 2). Wolfcamp carbonates were eventually deposited over the previously emergent arches and uplifts that mark the boundaries of the basin.

Although tectonic controls produced irregular sedimentation patterns and lateral lithic changes, the deep-basin brine aquifer (table 1) exhibits vertically uniform hydraulic heads and similar

Table 1. Generalized stratigraphic column, depositional environment, and general hydrologic properties, Palo Duro Basin.

System	Series	Group	General lithology and depositional setting	Hydrogeologic element	Hydrogeologic unit	Approximate permeability (gpd/ft ²)	Relative permeability
Quaternary			Fluvial and lacustrine clastics	Ogallala aquifer	Upper aquifer	200 [Ⓐ]	10 ⁸
Tertiary							
Cretaceous							
Triassic		Dockum	Fluvial deltaic and lacustrine clastics and limestones	Dockum aquifer		2 - 20(?) [Ⓑ]	10 ⁶ -10 ⁷ (?)
Permian	Ochoa		Salt, anhydrite, red beds and peritidal dolomite	Evaporite aquitard	Evaporite aquitard	2 x 10 ⁻⁶ [Ⓒ]	1
	Guadalupe	Artesia					
		Pease River					
	Leonard	Clear Fork					
		Wichita					
Pennsylvanian			Shelf and platform carbonates, basin shale and deltaic sandstones	Wolfcamp carbonate aquifer	Deep-basin brine aquifer	2 x 10 ⁻² [Ⓓ]	10 ⁴
				Pennsylvanian carbonate aquifer			
				Basin shale aquitard			
Mississippian			Shelf limestone and chert	Lower Paleozoic carbonate aquifer	Basin shale aquitard		
Ordovician		Ellenburger	Shelf dolomite				
Cambrian			Shallow marine(?) sandstone	Lower Paleozoic sandstone aquifer			
Precambrian			Igneous and metamorphic	Basement aquiclude	Basement aquiclude	0	0

Ⓐ Cronin and Wells (1960), Myers (1969), Cronin (1961)

Ⓑ Stevens (1980, written communication)

Ⓒ Geotechnical Engineers (1978)

Ⓓ This study

permeabilities (for further discussion, see p. 10); therefore all pre-Leonardian formations were grouped together into a single hydrogeologic unit for this preliminary regional analysis.

Middle and Upper Permian strata consist almost entirely of halite, anhydrite, dolomite, and fine-grained siliciclastic red beds, which grade southward into shallow-marine carbonates in the Midland Basin (Dutton and others, 1979). Together these formations compose the evaporite aquitard (table 1).

Overlying the Permian evaporites and red beds are the fluvial, deltaic, and lacustrine deposits of the Triassic Dockum Group and alluvial deposits of the Tertiary Ogallala Formation (fig. 5; table 1). The Dockum Group records the final stages of filling of the Permian Basin (McGowen and

others, 1979). Hydrogeologic information on Dockum sandstones is limited; wells over the basin tapping these beds have low specific capacities and produce waters that range widely in salinity. In contrast, potable ground water in the overlying Ogallala aquifer has been heavily pumped for agricultural, industrial, and domestic purposes. The Ogallala is an extensive alluvial apron of sand, gravel, and clay that extends eastward from the Rocky Mountains in the form of coalescing alluvial fan lobes (Seni, 1980). The upper part of the Ogallala Formation is cemented with calcium carbonate or "caliche" that forms the resistant "caprock" rim of the Caprock Escarpment along the eastern boundary of the High Plains (fig. 5).

Shallow, fresh ground waters generally move eastward under the influence of the regional

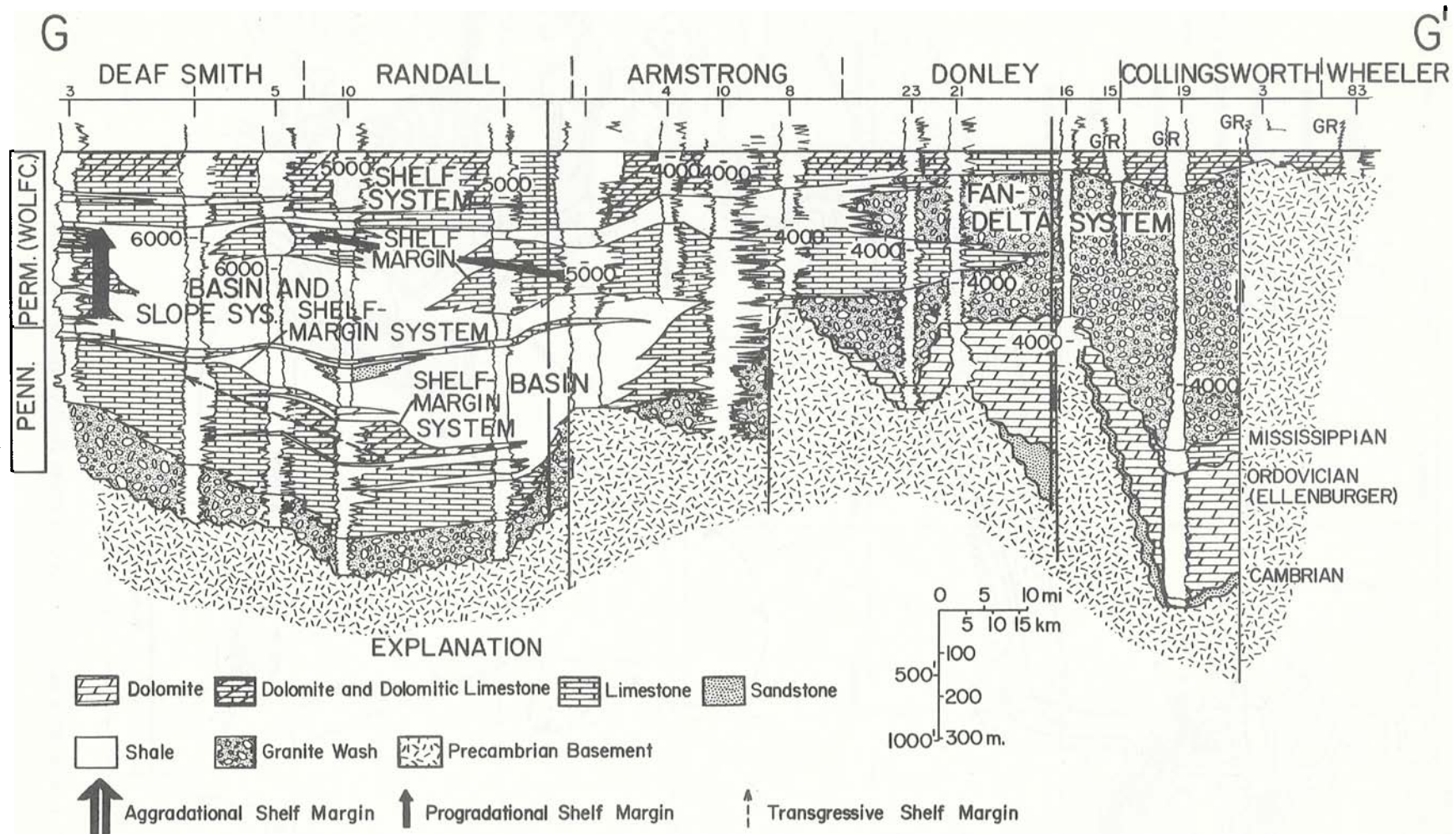


Figure 2. East-west cross section showing stratigraphic framework and depositional systems of Pennsylvanian-Lower Permian strata. Datum is top of Wolfcampian Series. Well logs are gamma ray (GR), spontaneous potential (SP), and resistivity (Res). Depths are in feet. See figure 1 for location (from Handford and Dutton, 1980).

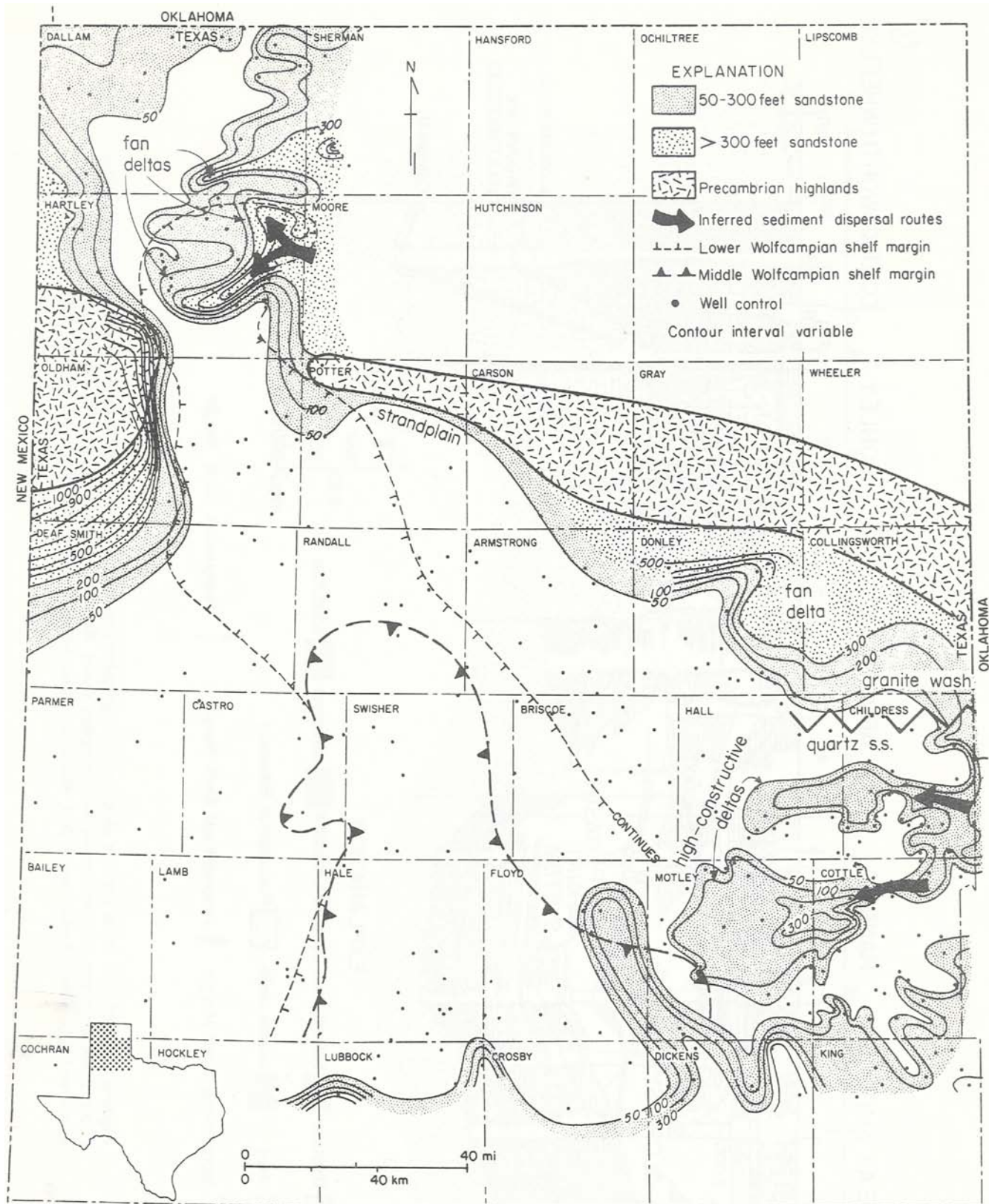


Figure 3. Net-sandstone map of Wolfcampian Series (from Dutton and others, 1979).

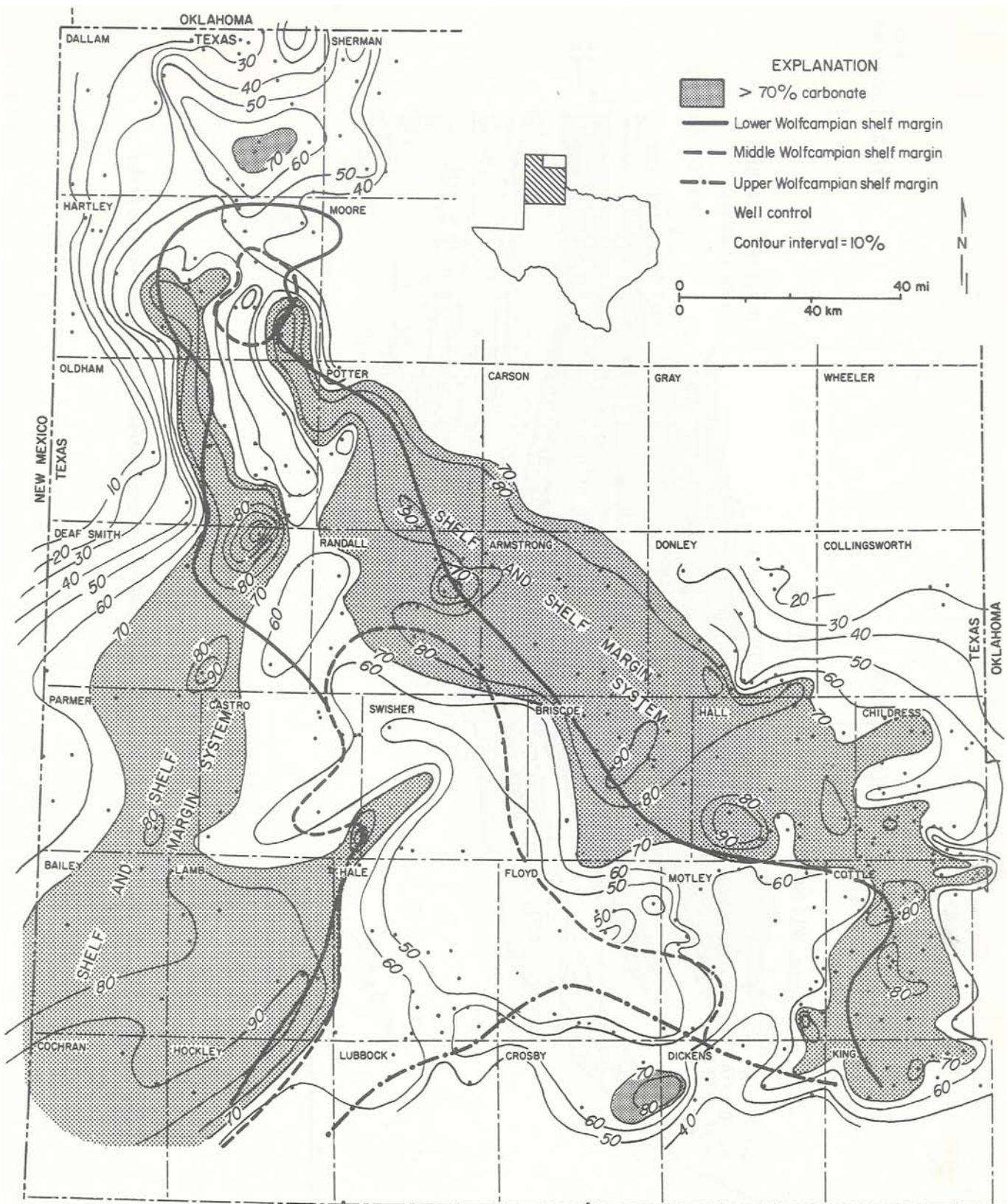


Figure 4. Percent carbonate map of Lower Permian Wolfcamp strata. Position of the shelf margin is shown by dashed line (from Handford, 1980).

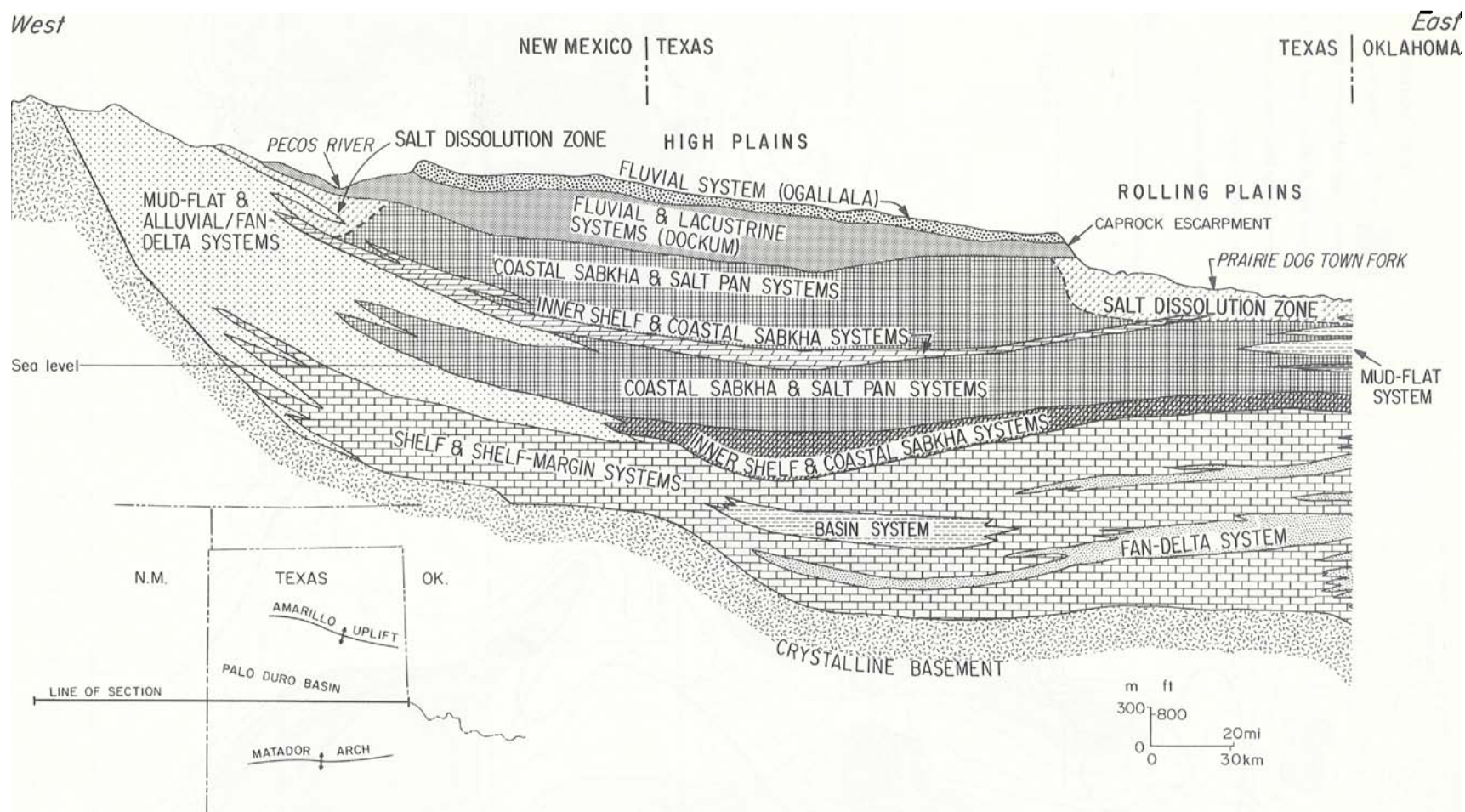


Figure 5. Regional east-west cross section illustrating spatial relations among the major depositional systems in the Palo Duro Basin.

structural and topographic dip (Cronin and Wells, 1960; Cronin, 1961; Gutentag and Weeks, 1980; Weeks and Gutentag, 1981; Texas Department of Water Resources, in press). Some of this water discharges as springs along the Caprock Escarpment (fig. 5). The middle and Upper Permian evaporite aquitard beds crop out east of the Caprock Escarpment in the Rolling Plains region, and here the weathered sediments yield moderate supplies of water for agriculture. In this Rolling Plains area, dissolution of halite and resultant collapse and disturbance of bedding have enhanced the permeability and porosity of overlying beds (Gustavson and others, 1980a). Salt dissolution, however, has led to formation of saline seeps and springs along eastward-draining stream courses, degrading the quality of surface waters for tens of miles downstream (Allen and others, 1971; Leifeste and others, 1971).

HYDROLOGY OF THE DEEP-BASIN FLOW SYSTEM

Sources of Hydraulic Data

Studies of deep, saline waters typically must rely on a more limited data base than do similar studies of shallow, more extensively developed aquifers because fewer wells are drilled to these depths and because hydraulic measurements are more difficult to obtain. The data used in this study came almost exclusively from the results of drill-stem tests (DST) conducted in petroleum wildcat wells, and from bottom-hole pressures measured in oil fields. Since there is no petroleum production in the central Palo Duro Basin, accurately measured fluid pressures presumably approximate natural pre-stress conditions.

Properly conducted drill-stem tests can yield adequate values of transmissivity, can approximate equilibrium fluid pressure, and, under appropriate conditions, can provide the distance to aquifer boundaries. During a typical drill-stem test, a section of the hole is isolated from the column of drilling mud by packers attached to a string of drill pipe. A valve is opened and formation fluid flows through perforations and into the pipe, typically for 15 minutes to 2 hours. The valve is closed (the formation is "shut in") to

allow recovery of pressure in the formation. The time required for substantially complete pressure recovery is longer if permeability is low or if a large volume of fluid is removed. In many tests, reported final pressures are too low because of incomplete recovery owing to insufficient shut-in time. The calculated head, of course, will also be too low under such conditions. The trend of pressure build-up must be extrapolated to determine true formation-fluid pressure. Other, sometimes large, deviations from true pressures are caused by the mechanical and operational difficulties of drill-stem testing.

The most useful and accurate drill-stem-test information is obtained from the actual pressure/time charts recorded downhole. Proper performance of the test tools can be confirmed by visual inspection of these charts (Black, 1956); the valid records can then be analyzed to determine aquifer characteristics. A few complete pressure/time charts were available; these were analyzed to determine true formation-fluid pressures by extrapolation to infinite time and to obtain representative permeability values.

The pressure/time charts were analyzed according to methods outlined in Matthews and Russell (1967) and Earlougher (1977). Most of the pressure build-up data formed a straight line when plotted in semilog form, as predicted by the Horner (1951) method (appendix A). In many cases, the initial shut-in pressure (ISIP) extrapolated from data from the first shut-in period approximates the final shut-in pressure (FSIP) from the second pressure build-up. If these two pressures are equal, the aquifer tested may be relatively large, or "infinite acting" (Earlougher, 1977). The two principal causes of unequal shut-in pressures are depressuring (depletion) of a small, isolated aquifer by fluid removal and supercharging. Invasion of drilling mud can increase (supercharge) the pressure around the well bore before testing, especially if formation pressures are much lower than the pressure exerted by the column of drilling mud. In the Palo Duro Basin, the fluid pressures are generally less than hydrostatic (subnormal for a given depth), a condition that is conducive to supercharging. Numerous notations on sample logs of lost circulation of mud indicate that the combination of low formation pressures and high mud weight makes mud invasion common. A small number of the analyzed drill-stem tests showed anomalously high pressures

that may be due to supercharging; however, if the first flowing period is longer than five minutes, the supercharged condition is usually rectified. Depletion results in lowered pressures.

The number of derived permeability values is small, given the large volume of rock in the basin. Moreover, the permeability values measured in any given well are greatly dependent on the interval chosen for testing; these decisions are usually based on hydrocarbon shows rather than on other physical criteria such as high porosity indicated by electric logs. The most permeable parts of the deep formations may be untested. These data are summarized in appendix A.

Formation-fluid pressures were converted to an equivalent fresh-water head (specific gravity = 1.0). On the basis of estimates made from values of total dissolved solids (TDS), specific gravity of brines in the Palo Duro Basin ranges from about 1.05 to 1.13. The range of specific gravities is too small to cancel or to reverse the apparent directions of the calculated fresh-water head gradients (Bond, 1972).

The head map for the Wolfcamp aquifer was constructed principally from more than 400 pressure values reported in commercial digitized drill-stem-test summaries; 23 extrapolated pressures controlled the accuracy of the generalized head contours. Inspection or analysis of several pressure/time charts of the same drill-stem tests that reported anomalous pressure values showed that their rejection was justified. The most common errors were (1) insufficient shut-in time, probably owing to very low permeability, (2) clerical error in reporting pressures to the commercial drill-stem-test service, (3) tool failure, or (4) supercharging. Most of the differences between true and reported pressure values were small, low-side deviations apparently caused by slightly insufficient shut-in times. However, since horizontal pressure gradients in the Wolfcamp aquifer are great compared with the latter type of error, the data quality was sufficient to determine general magnitudes of pressures and of the resulting horizontal head gradients.

Hydrodynamics

Computed fresh-water hydraulic heads in the Wolfcamp carbonate aquifer decline from west to east (fig. 6), reflecting the regional topographic

and structural dip away from the Rocky Mountains. Eastward decline of head values also occurs in brines in both the Midland Basin south of the study area (McNeal, 1965), and in the Mid-continent province to the north (Larson, 1971). At all test points in the Palo Duro Basin, the heads in aquifers below the Wolfcamp are similar. Although vertical leakage across aquitards may be significant owing to the large contact area between formations, locating where leakage may occur is difficult because of low density and unreliable data. Least-squares analysis of pressure and depth data from all uncorrected drill-stem-test reports yielded slopes equivalent to the pressure gradient in static or horizontally flowing typical brines (Bentley, 1981). Therefore, the assumption of predominantly horizontal flow in the basin appears valid.

The 19 calculated permeability values for Wolfcamp carbonates ranged from 0.03 to 44 md, with a mean of 5.3 md and a median of 0.77 md (appendix A, table A-1). Most values are between 0.1 and 10 md (fig. 7), and a value of 2 md was adopted for estimation of flow velocities. The Wolfcamp dolomite locally has higher permeability over the Amarillo Uplift in the Panhandle oil and gas field, where early postdepositional flushing by meteoric waters produced solution cavities sufficiently large to cause drill-bit drops several feet deep (J. Nicholson, personal communication, 1980).

Aside from the regional west-to-east fluid migration pattern, topography appears to exert little control on deep-basin circulation. A major topographic feature in the study area is the Caprock Escarpment (figs. 5 and 8), which has over 1,000 ft (305 m) of relief within a few miles. Head contours (fig. 6) do not correlate with this feature. Beneath the High Plains (west of the escarpment), deep-basin fresh-water heads are approximately 1,200 to 2,200 ft (366 to 671 m) below land surface, and east of the escarpment, heads in the same system occur at the level of the land surface. It is possible that present conditions may be transient and that pressures at depth may be slowly increasing due to hydraulic conditions imposed more recently by the younger, shallow systems.

The Panhandle field gas reservoir is capped by anhydritic limestone that forms the base of the overlying evaporite section. Initial fluid pres-

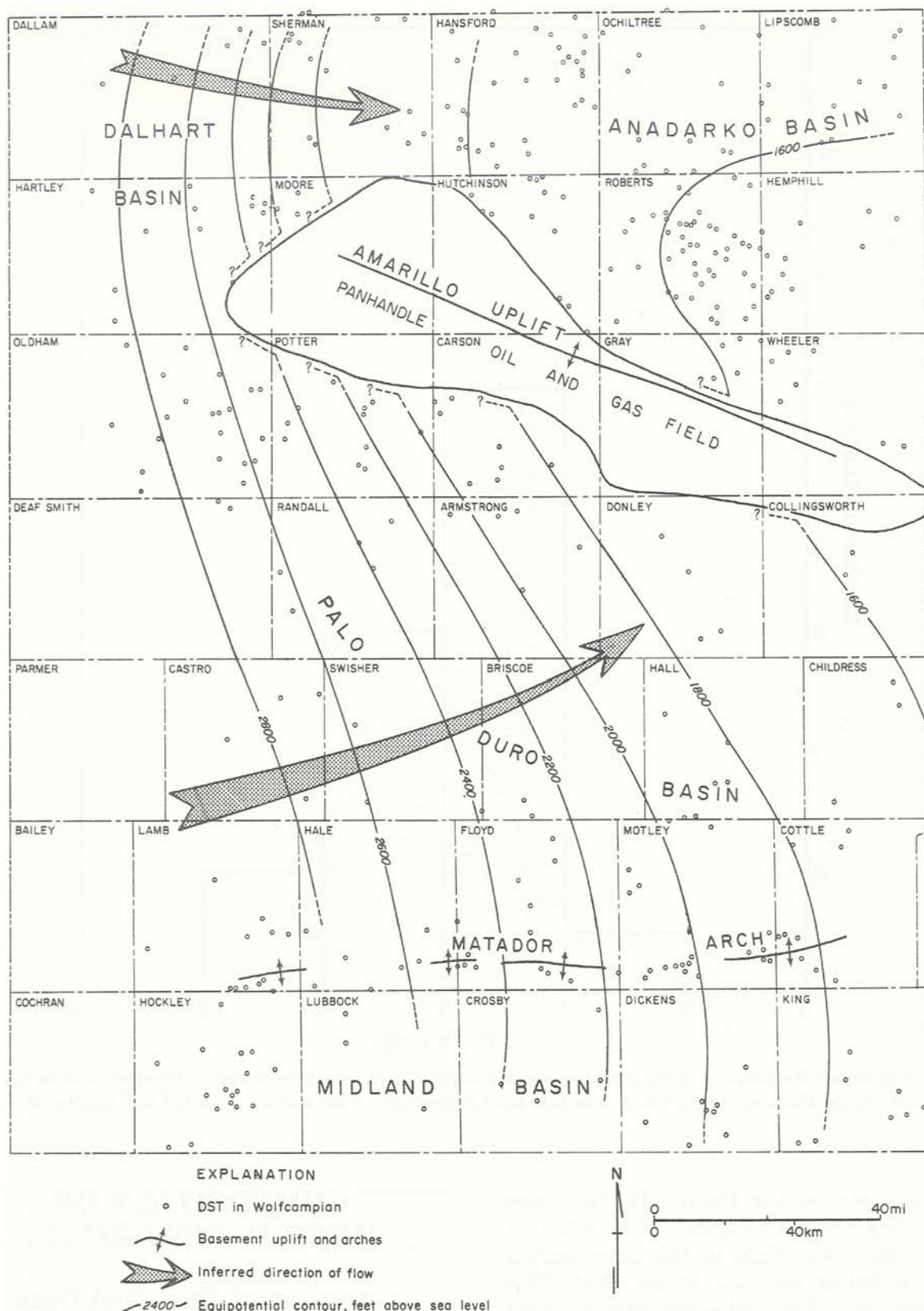


Figure 6. Hydraulic head map, Wolfcamp aquifer, Texas Panhandle. Head contours interpreted from fresh-water head values calculated from uncorrected shut-in pressures. Low head values (1,000 ft) in the Panhandle oil and gas field appear to cut across regional trends and may represent relative hydraulic isolation of eastward-drained porous strata. Well locations not shown in the Panhandle field.

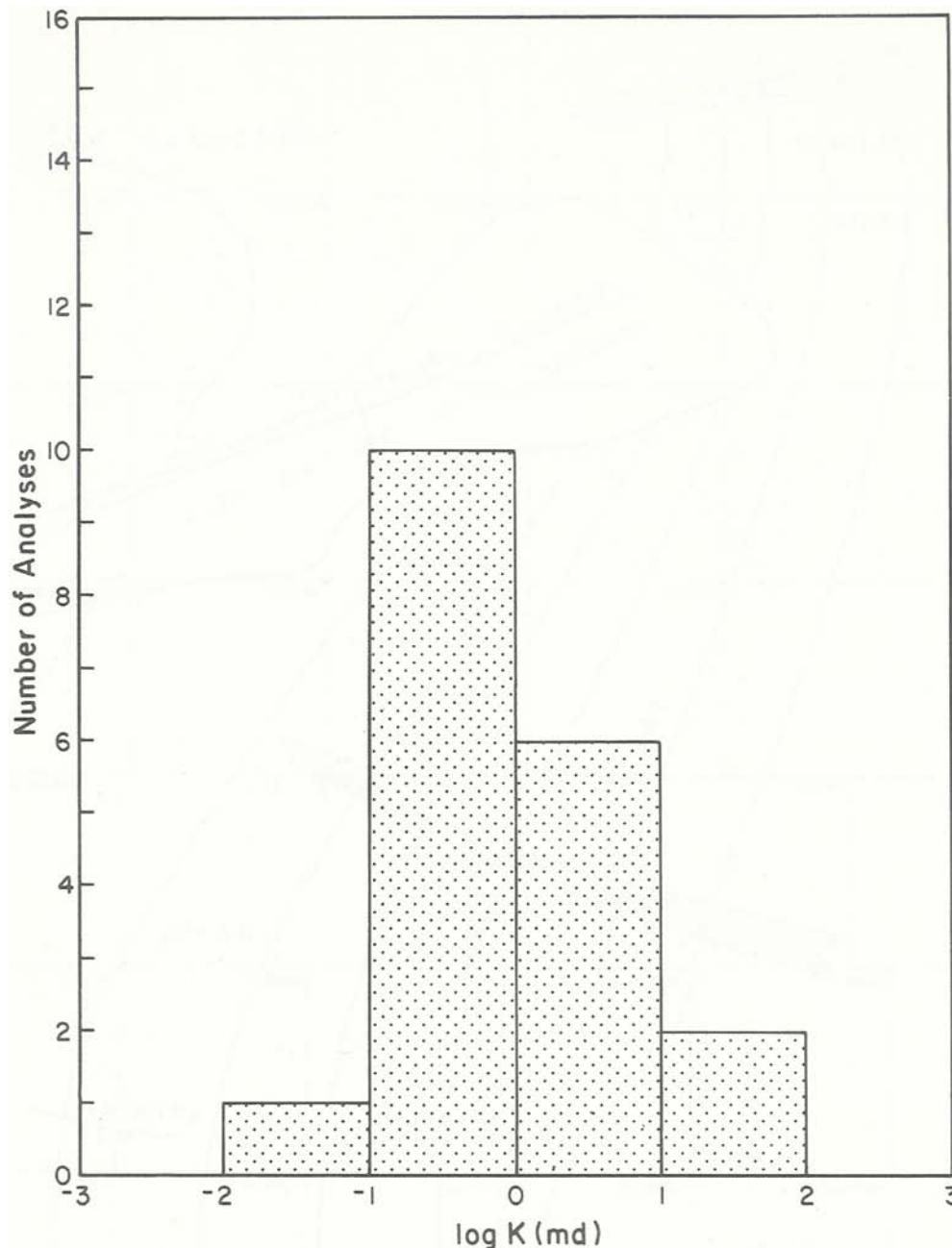


Figure 7. Frequency distribution of the effective permeability in Wolfcamp carbonates determined by analysis of 19 drill-stem-test charts. Data range from 0.03 to 44 md, with a mean of 5.3 md and a median of 0.77 md (see table A-1).

sure everywhere in the Panhandle field was approximately 435 psi (Rogatz, 1939), which is about 265 psi lower than in the brine-bearing rocks immediately adjacent to the field. This abrupt pressure differential is apparently caused by faults that effectively isolate the reservoir from laterally adjacent parts of the Wolfcamp aquifer.

COMPOSITION OF DEEP-BASIN BRINES

Sources of Chemical Data

Chemical compositions of fluids used in this investigation were obtained from petroleum

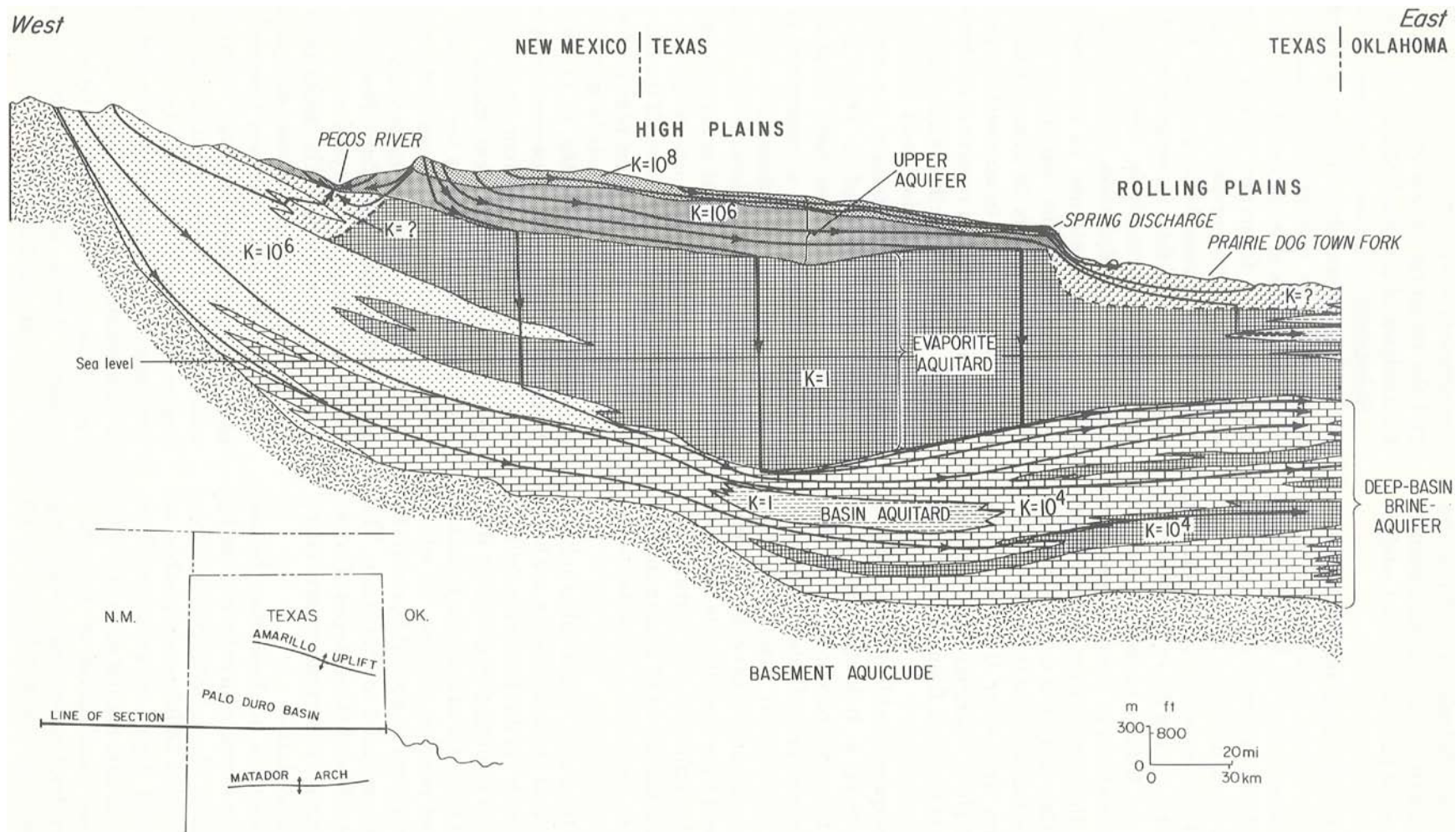


Figure 8. Regional east-west section approximately parallel to flow, illustrating the distribution of major hydrogeologic units (table 1) and their corresponding relative permeabilities (k). Flow lines are intended to describe conceptual flow patterns on the basis of head distribution and relative average permeabilities.

companies and from petroleum information companies. These analyses are predominantly from samples that were collected during wildcat drilling programs.

Brine compositions that most nearly represent the composition of the in situ formation fluid are from samples collected after a drill-stem test ended. Most tests of wildcat wells are conducted primarily to determine the presence of hydrocarbons and secondarily to determine reservoir permeability. During the recovery part of the test, fluid derived from a packed-off section passes through perforations in the drill-stem-test tool and enters the drill stem. The more sophisticated drill-stem-test tools contain sample chambers that allow collection of the last brine to leave the formation and enter the tool. More commonly, the sample is collected from the last string of pipe as it is removed from the drill hole after the test.

Samples of more questionable quality may be collected directly from a holding tank of a producing well or from the borehole by bailing. Obviously, such samples are collected under non-ideal conditions, and their usefulness for geochemical interpretation is severely limited. Analysis of minor and trace constituents is seldom done, and any such analysis would certainly be suspect owing to the likelihood of contamination from drilling fluids, hardware, or containment vessels.

Using several thousand chemical analyses from the Palo Duro and Dalhart Basins, we have deleted those for which (1) dilution with drilling fluid is suspected, (2) information indicates that the brine originated from a production or injection well in an enhanced recovery process, (3) either depth or location data are unavailable, or (4) the tested formation is unrelated to this study. The remaining data are subject to three types of error: (1) collection procedure, (2) sample preservation, and (3) analytical procedure.

Chemical compositions of formation brines historically have been found to have limited use by the petroleum industry. The industry requires only approximate information on brine composition to calibrate geophysical logs, to evaluate fluid compatibilities, to evaluate scaling and corrosion, and to make gross correlations of hydraulic connection in reservoirs. Consequently, sampling and preservation techniques generally have been

commensurate with the intended use of the data, and the resulting values frequently are ill-suited for analysis of the geochemistry of a system.

Substantial outgassing of volatiles will occur as the fluid is brought to the surface and exposed to atmospheric conditions, unless special precautions are taken to prevent it. Our investigation indicates that formation brines in the region exhibit CO_2 partial pressures (P_{CO_2}) significantly higher than atmospheric pressure (fig. 9). The consequences of this are outgassing of CO_2 from the brine before analysis, elevation in pH, and possibly the precipitation of carbonate minerals in the sample container, as discussed in a subsequent section. The oxidation state of the sample will obviously be altered with the loss of H_2S or the exposure to atmospheric oxygen. It is occasionally noted on reports of analyses that the samples appear rusty; this is most likely caused by ferrous iron oxidation and precipitation of hydrated ferric hydroxides in the sample bottle.

The composition of a brine generally is determined in a laboratory operated by the drilling company or in a commercial laboratory. Results are seldom presented with tabulated cation and anion balances. In addition, our computations reveal that many analyses balance exactly, indicating that one or more constituents are determined by difference. Of the 121 analytical results selected as acceptable for further interpretive work, few include more than major constituents (Na, K, Ca, Mg, HCO_3 , SO_4 , and Cl). Moreover, the sodium value commonly represents the sum of both potassium and sodium. Temperature, pH, and a few minor components (H_2S , Sr, Br, and Si) rarely are included. The data selected for this study are included in appendix B.

We tried to locate brine-producing petroleum wells within the Palo Duro Basin so that the results of complete analyses of brines could be presented in this study. The majority of oil fields are undergoing or have been subjected to some form of enhanced oil recovery treatment (such as chemical treatments or water flooding through reinjection). Such treatment is common in this region because of naturally low formation pressures. We concluded that successful sampling of representative formation brine was highly unlikely and that the available brine compositions obtained during wildcat exploration programs would be the most useful.

Well density within the basin is extremely sparse. Consequently, few chemical data are available from the central basin area; most are from marginal areas. A location map shows field location and brine-sample sources (fig. 9).

Geophysical Data and Regional Salinity

Geologists at the BEG used more than 5,000 geophysical logs to interpret the stratigraphic sequences in the Palo Duro and Dalhart Basins (Dutton and others, 1979; Gustavson and others, 1980b). Electric logs are particularly useful for lithologic correlation, and spontaneous potential (SP) logs additionally may be used as an indicator of fluid resistivity (Keys and MacCary, 1971; Schlumberger, 1972). Resistivity of the formation water is measured relative to the resistivity of the borehole fluid, then converted to an equivalent resistivity (or salinity) of a sodium chloride solution. According to Keys and MacCary (1971), at least three assumptions must hold: (1) both fluids must be dominantly sodium chloride; (2) shales must be treated as ideal membranes; and (3) formation fluid and matrix should have a lower resistivity than borehole fluid. If these constraints are satisfied, then the following relation may be used:

$$SP = -K \log (R_m/R_w)$$

SP = deflection in SP log (mV)

$K = 60 + 0.133 T$

T = temperature at the formation depth (°F)

R_m = resistivity of the borehole fluid (ohm-m)

R_w = resistivity of the formation water (ohm-m)

Brines from the Palo Duro Basin appear to meet the above criteria. Information about drilling fluids tested at the well is given in the header of each log chart. Spontaneous potential logs from Wolfcamp carbonates or granite-wash facies that satisfied the prerequisites of the method were selected for computation. Resistivities (or salinities) were computed and the values converted to TDS as sodium chloride (g/L), then plotted on isopach maps of both Wolfcamp and granite-wash facies (figs. 10 and 11). Formation factors and computed salinities used in those figures are tabulated in appendix C. For comparison,

the values of dissolved solids from actual chemical analyses are also included on the map, and a reasonable similarity is apparent. The maps indicate that there is little need to correct the fresh-water head map for salinity difference (fig. 6), owing to the rather uniform salinity across the Palo Duro Basin. In the Anadarko Basin north of the Amarillo Uplift, higher salinities exist. This anomaly may be explained by the relative hydraulic isolation and long residence times. Hydraulic isolation is evidenced by overpressure in the deep Anadarko Basin east of the mapped area.

GEOCHEMICAL CONSTRAINTS ON THE BRINE ENVIRONMENT

Defining Reactions and Chemical Composition

Brines produced from Upper Pennsylvanian and Lower Permian formations in the Palo Duro Basin appear to be part of a continuous system, moving eastward under a gradient of less than 6.3 ft/mi (2 m/km). Lithostratigraphy below the evaporites in this basin is dominated by carbonates (limestone, micritic limestone, dolomite) and substantial intertongued arkosic clastic facies. Because of the regional nature of brine migration, the lateral continuity of carbonate facies, and the long residence and reaction times, it might be expected that the brine composition would reflect the composition of the host rock. Dissolved solids values from chemical determinations and geophysical data are similar; however, we know less about regional variations of individual concentrations.

Typical of sedimentary basins, brine composition is dominated by sodium chloride, and salinity is several times that of seawater. A number of mechanisms have been proposed to describe the evolution of brines, such as membrane filtration, dissolution of evaporites, or mixing with metamorphic or magmatic waters (Berry, 1958; White, 1965; Hanshaw and Bredehoeft, 1968a, b; Carpenter, 1978). Development of salinity in this basin is probably related to the presence of evaporites. Of incidental note is the absence of post-Paleozoic magmatic activity within the basin

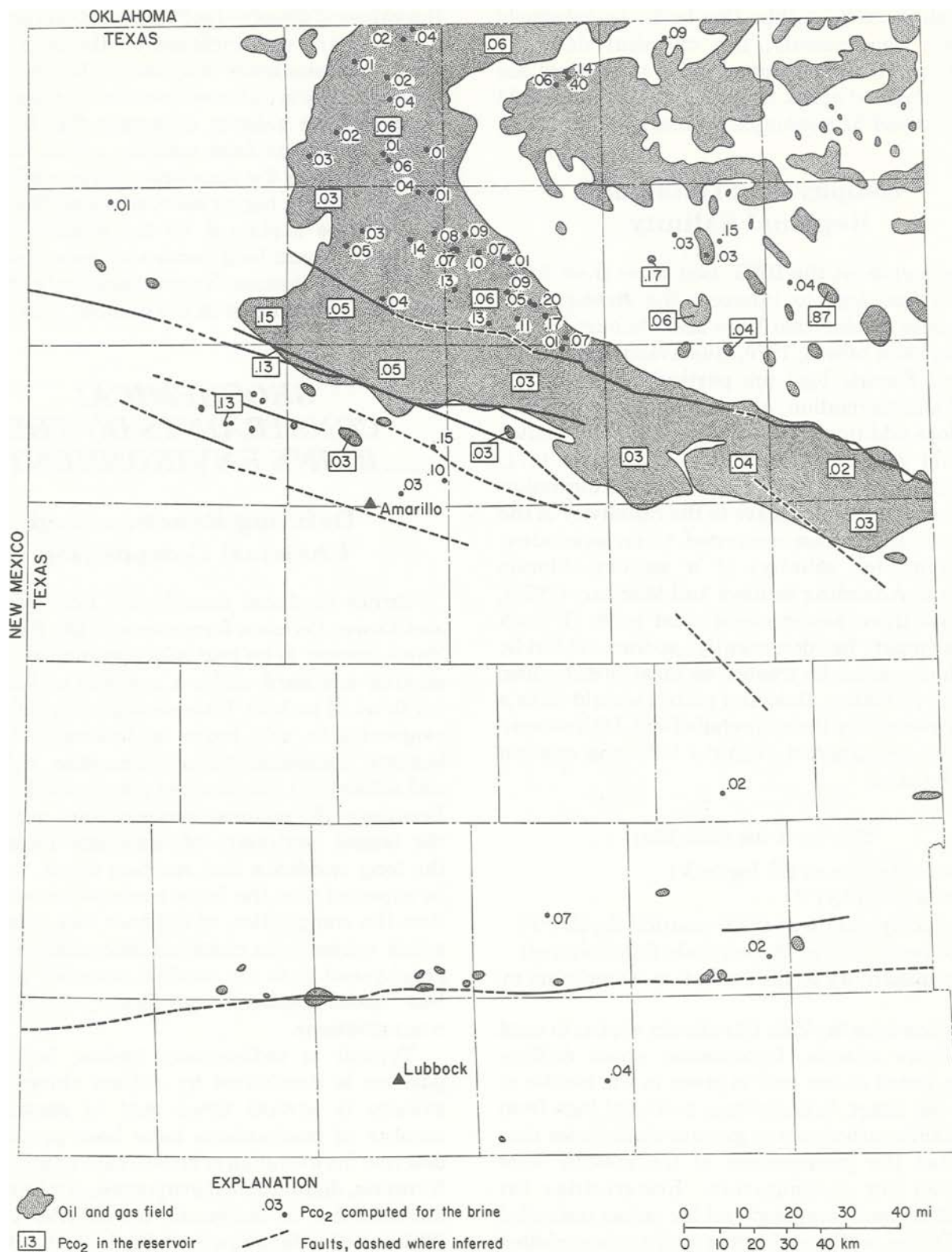


Figure 9. Location map showing (1) the P_{CO_2} of oil and gas fields computed from analyses of gas samples (from Moore, 1976), and (2) the P_{CO_2} computed from analytical results obtained from brine in wildcat and production wells. The distribution of oil and gas fields in the Dalhart and Palo Duro Basins is derived from Best (1961), Johnson (1976), Birsa (1977), Panhandle Geological Society (1961), Petroleum Information Corporation (1980), and the map files located at the Texas Railroad Commission. Structure information from A. Goldstein (written communication, 1981).

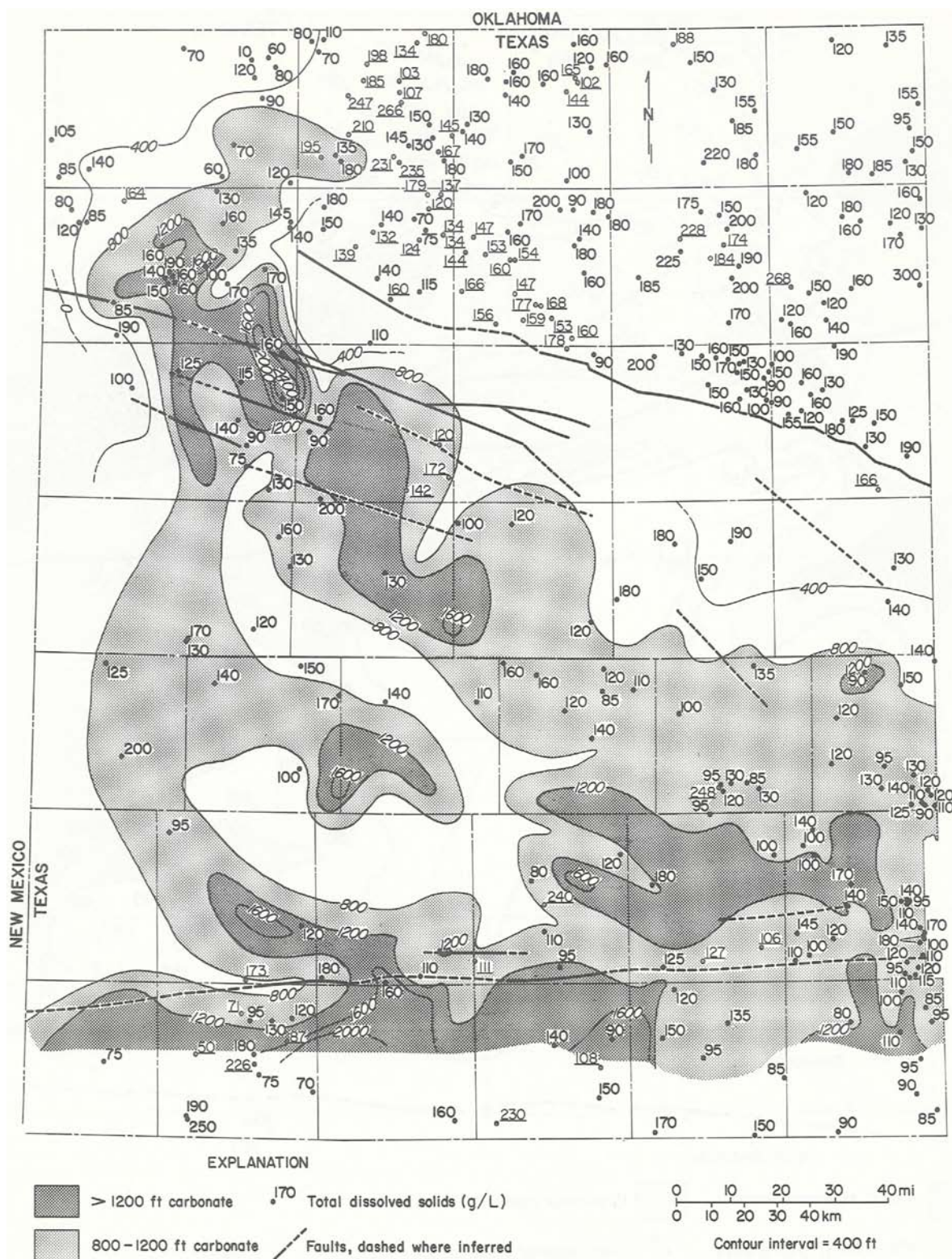


Figure 10. Contour lines showing carbonate isoliths for the Wolfcampian-age section of the deep-basin brine aquifer (from C. R. Handford, written communication, 1981). Data points indicate total dissolved solids (g/L) from chemical analyses of the brines (see underlined data, this figure, which are from appendix B, table B-1) or computed from spontaneous potential logs (see appendix C, table C-1). Structure data are from A. Goldstein (written communication, 1981).

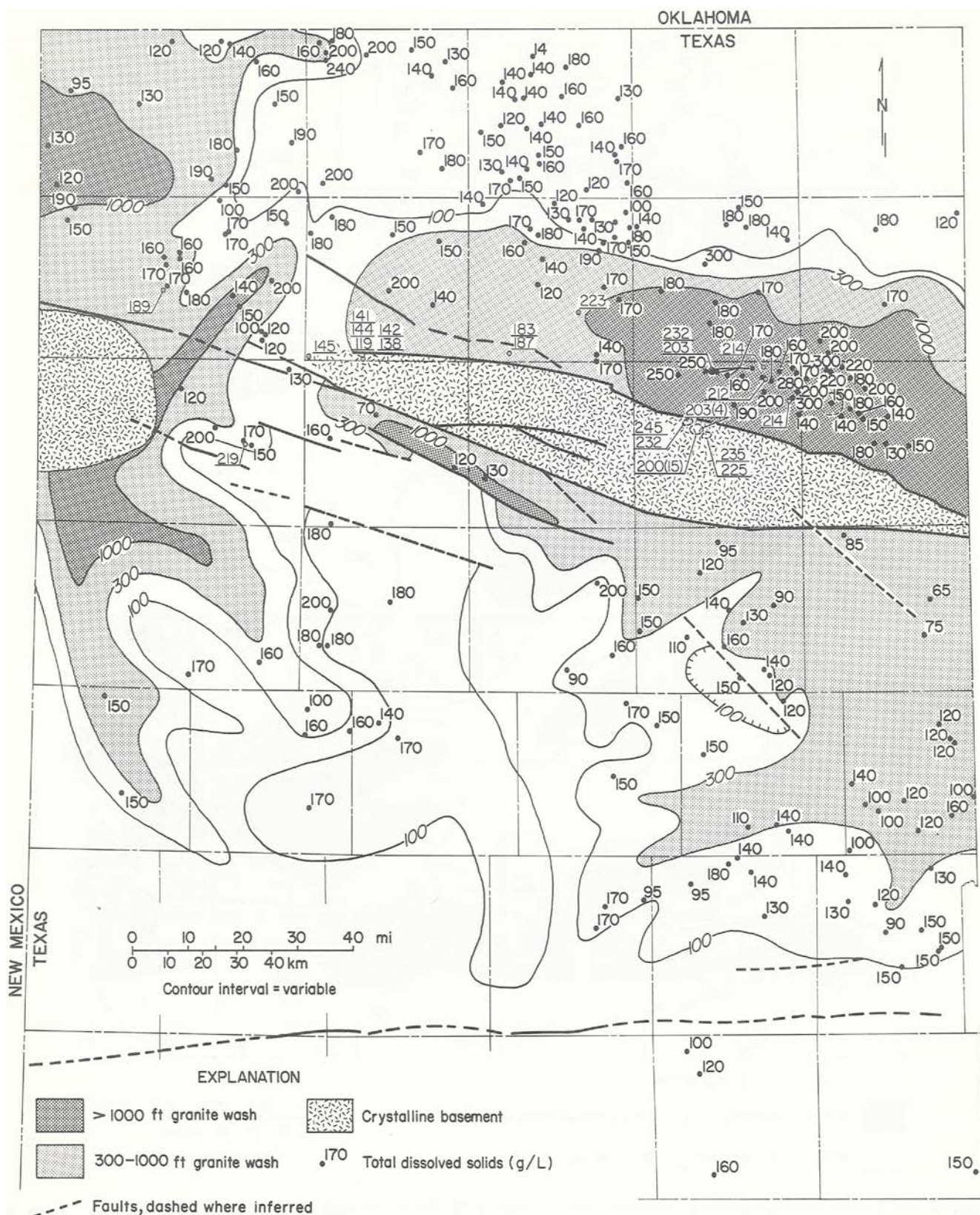


Figure 11. Contour lines showing isopachous map of granite wash in the deep-basin brine aquifer (from Dutton, 1982). Data points indicate total dissolved solids (g/L) from chemical analyses of the brines (see underlined data, this figure, which are from appendix B, table B-1) or computed from spontaneous potential logs (see appendix C, table C-2). Structure data are from A. Goldstein (written communication, 1981).

and the absence of membrane effects in any detected chemical or head gradients. Mudstones and shales required for membrane filtration are volumetrically of little significance in this basin, which is dominated by chemical precipitates (evaporites), coarse-grained siliciclastic sediments, and carbonates.

Carpenter (1978) suggested that, in sedimentary basins, brine compositions greater than 100,000 mg/L TDS are influenced by evaporite dissolution. The deep formations in the Palo Duro and Dalhart Basins have been overlain by evaporites since Late Permian time. At present, the hydraulic head declines with depth through the evaporite section below the topographically elevated Southern High Plains, and any fluid migrating through this section would be saturated with sodium chloride. Upon discharge from the evaporites, this fluid would mix with brines in the Wolfcamp carbonates (fig. 5). Permeability of the evaporites is extremely low (table 1); consequently, flux through this section must be low. Although some mixing with waters leaking downward from evaporite lithologies has surely occurred, a more reasonable source of the salinity would be from dissolution occurring earlier in the flow history and originating relatively near the recharge areas to the west (figs. 5 and 8).

Ancient salt dissolution zones (originating as early as the Triassic) have been identified near the margins of the basin (Gustavson and others, 1980a). Regional hydraulic gradients during the Triassic are uncertain; however, the Panhandle area was still a topographic low, as evidenced by convergence of sediments from surrounding fluvial to lacustrine sources (McGowen and others, 1980).

During the Late Cretaceous, the Panhandle area was still at or below sea level, and broad carbonate platforms covered the Triassic basin fill. Marine regression accompanied by Laramide tectonism (Late Cretaceous to Paleocene) in New Mexico most likely initiated the ambient regional eastward topographic and hydraulic gradients. Fluids migrating through the deep basin may have entered the system primarily in New Mexico. Owing to the extreme anisotropy between vertical permeability in the evaporites and horizontal permeability in the carbonates (a ratio of $1:10^6$), most recharge may come from areas where outcropping aquifers are juxtaposed with updip

limits of evaporite beds undergoing dissolution. If hydraulic gradients shown in figure 6 have remained unchanged since the Late Cretaceous, and if permeability and porosity of 2.0 md and 0.5 percent can be considered average for the carbonates (Bentley, 1981), then the fluid from western recharge areas could replace the basinal brines in cycles of about one million years. After the Laramide Orogeny, the entire mass of fluid in Wolfcampian age strata from outcrop to the basin center may have been displaced more than 60 times. Any residual brine from the sabkha deposits would have been displaced early in the development of the regional flow regime. Brines present today in the carbonate rocks and sandstones cannot be connate water. Original fluids have been driven out by the regional flow, and the character of the brines is dominated by dissolution of evaporites early in the flow path and by subsequent modification in transit.

Compositions of both Wolfcamp carbonate (fig. 12) and Pennsylvanian-Permian granite-wash brines (fig. 13) have been plotted on trilinear diagrams. A prominent feature of the pattern is the predominance of sodium chloride. Of the 121 values plotted for Wolfcamp samples, most are aligned along a ray emerging from the Na apex, which indicates a common Mg/Ca ratio.

The slope of the salinity ray of fluids in carbonates (fig. 12) corresponds to a higher Mg/Ca ratio than that of fluids in clastics (fig. 13), suggesting that brines in the granite-wash facies are depleted in magnesium or that the calcium content has been elevated. The sulfate concentration in granite-wash brines is also significantly lower than in Wolfcamp carbonates, commonly by two orders of magnitude. It was noted even in the earliest production reports that fields developed in granite wash, particularly north of the Amarillo Mountains, produce hydrogen sulfide. Sulfate reduction with continued dissolution of anhydrite would in effect elevate calcium and deplete sulfate concentrations.

The data to determine the most likely source of calcium are presently unavailable. It is possible that albitization of intermediate plagioclases in the sandstones and granite washes is contributing substantial calcium to the system. The mechanism will be investigated in detail when new core holes are completed in the basin. Brine samples will be

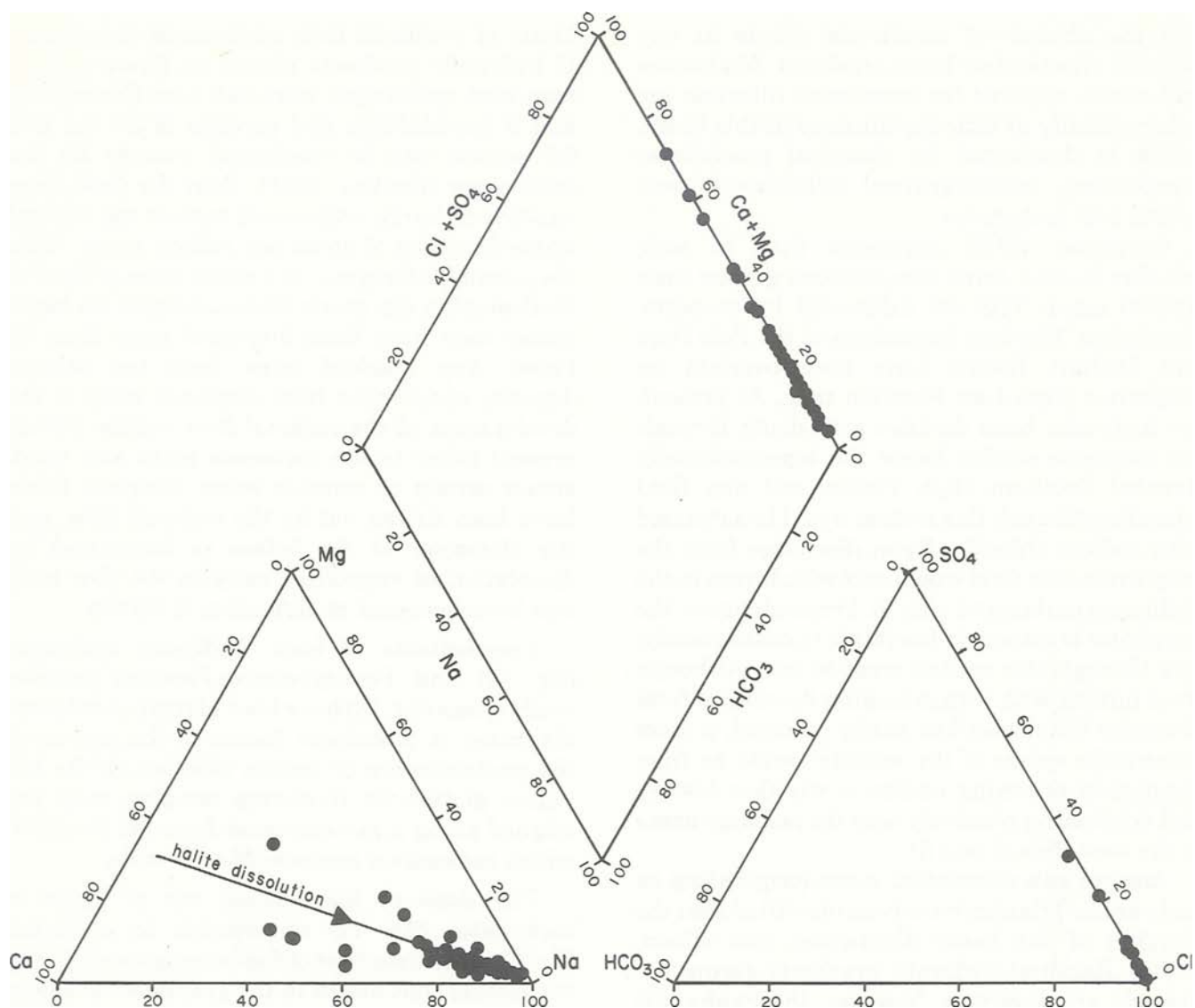


Figure 12. Trilinear diagram illustrating the compositional variation of brine samples from the Permian Wolfcamp carbonate aquifer.

collected for chemical analysis, and petrographic examination of siliciclastics may provide evidence of albitization if the process is active.

To identify the thermodynamic constraints on brine compositions, we used a computer model, AQ/SALT, which was designed specifically for application to brines. AQ/SALT computes the activity coefficients for components in the brine using the results of analyzed concentrations and then determines the reaction state of the brine with respect to many common minerals in the host rock (Barnes and Clarke, 1980) (see p. 23 for further discussion). Granite-wash and Wolfcamp carbonate brines were computer-processed

separately; the saturation states with respect to halite and anhydrite are illustrated in figures 14 and 15. Wolfcamp carbonate brines cluster relatively near equilibrium with anhydrite and show a significant degree of undersaturation with respect to halite. In contrast, the deeper granite-wash values appear to be shifted away from saturation with anhydrite, most likely in response to sulfate reduction. In addition to the original calibration with solubility data that the model received during development, a test of the accuracy of the model is provided with the two samples. Samples 1 and 2 were collected from Bristol Dry Lake, California, a continental sab-

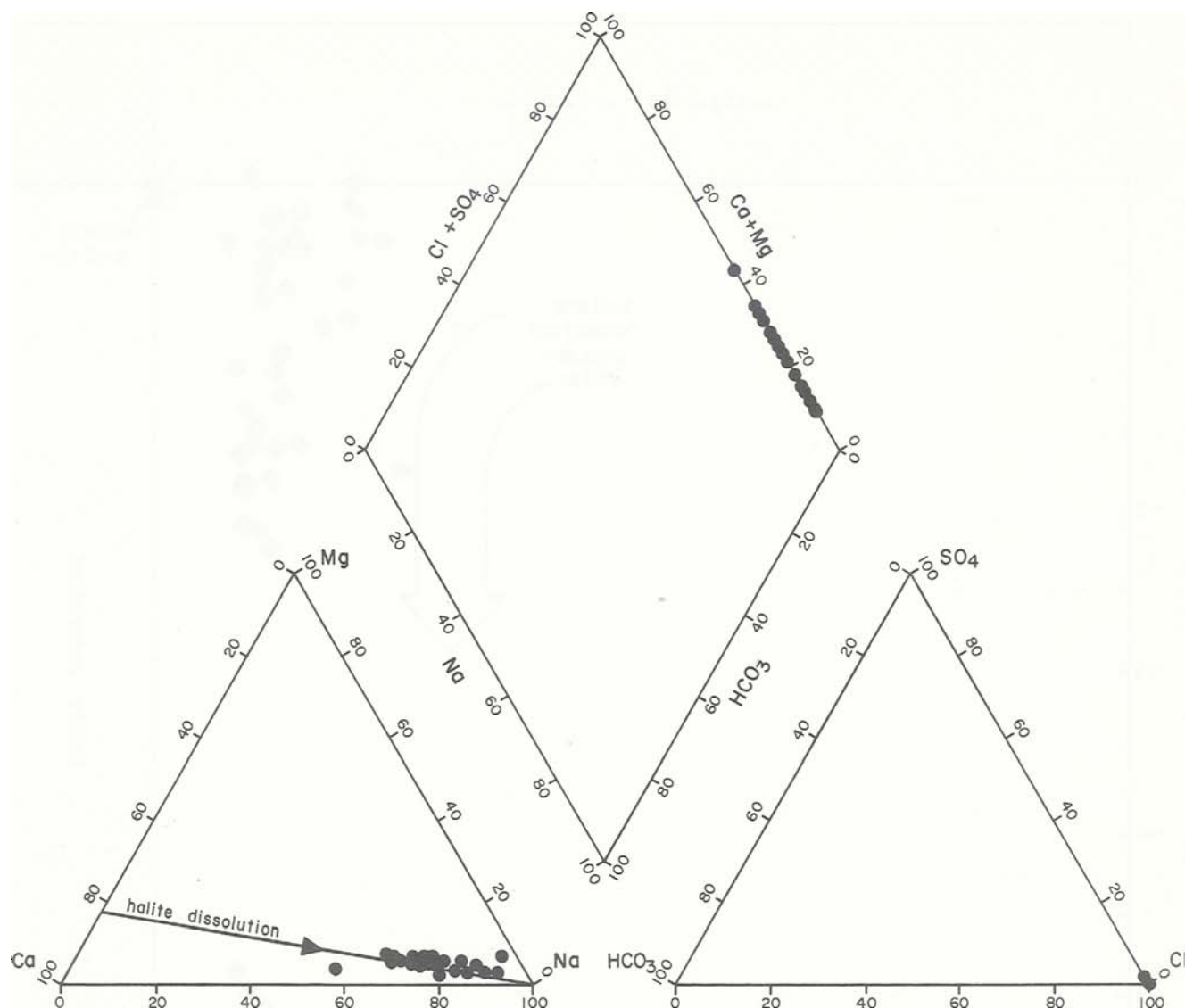


Figure 13. Trilinear diagram illustrating the compositional variation of brine samples from the Pennsylvanian-Permian granite-wash facies.

kha in which both halite and anhydrite are precipitating. These two brine analyses plot at the point of simultaneous equilibrium with halite and anhydrite (see samples 1 and 2, plotted on figs. 14 and 15).

If the source of sodium and chloride is dissolution of halite early in the flow path or mixing with fluids leaking from the overlying evaporite section, then the ratio of sodium to chloride (mg/L) should be very near the theoretical value of 0.65. Ratios for both brine types are indicating some perturbation from the ideal value (figs. 16 and 17). As might be expected, Wolf-camp carbonate brines, which are shallower and

occur adjacent to the evaporite facies, have compositions that are only slightly offset from the theoretical ratio, whereas the compositional shift for granite-wash brines is more pronounced, probably as a result of ion exchange. Even though the clastic sediments are of marine origin and contain large amounts of exchangeable sodium from equilibrium with seawater, the elevated sodium in these deep basinal brines will continue to drive calcium and magnesium from the clay. Exchange consequently depletes sodium relative to chloride. The sandstone and granite-wash facies are significantly rich in clay minerals, providing substantial ion exchange capacity.

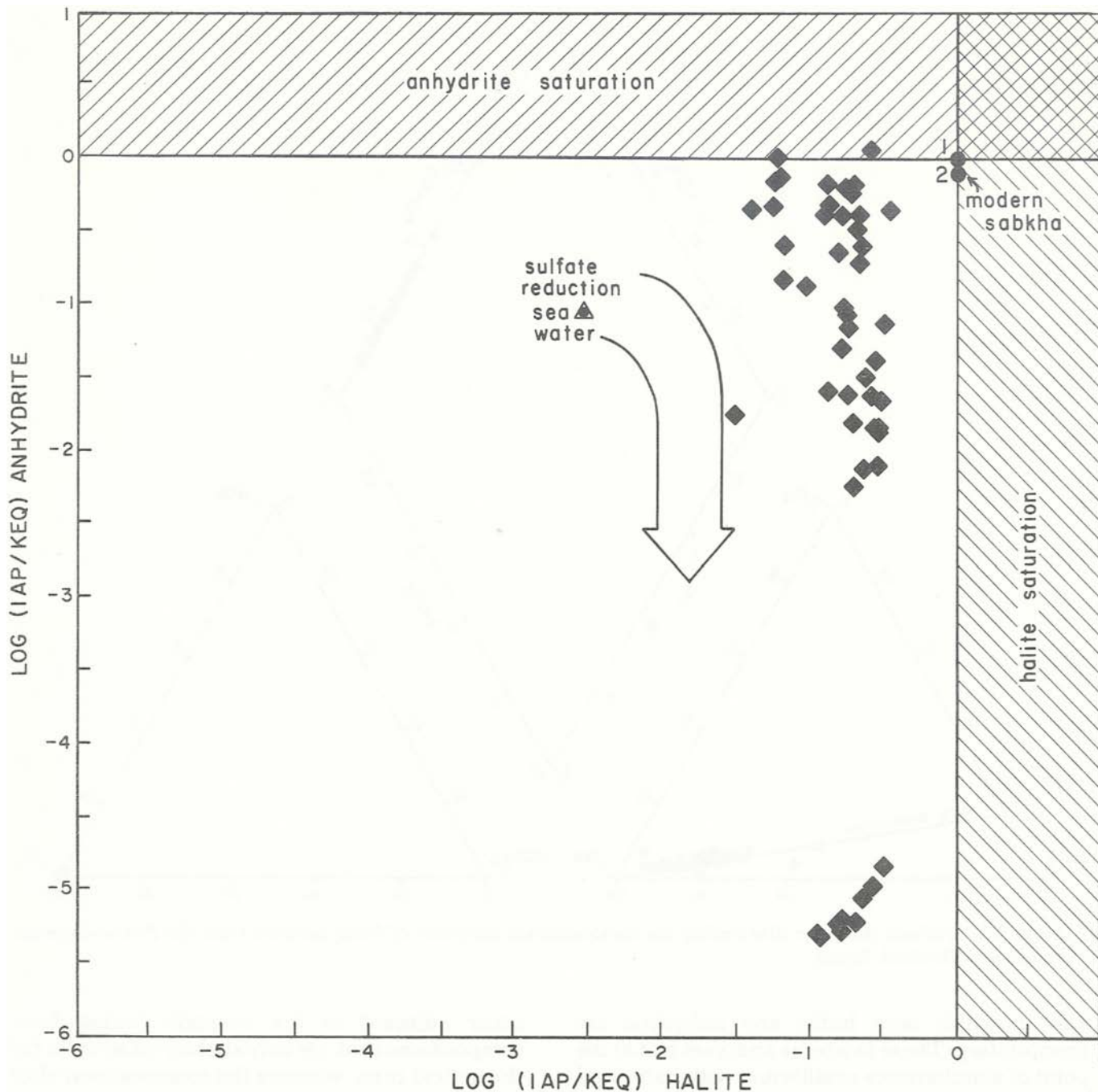


Figure 14. Saturation state of brine samples from the granite-wash facies as computed with AQ/SALT. The arrow indicates the suspected direction of movement away from the anhydrite phase boundary with continued sulfate reduction. However, this is not intended as a quantitative prediction of the actual reaction path.

The potassium content of brines in the Palo Duro Basin is not accurately known; potassium usually is reported as sodium. The close association of Palo Duro brines with evaporite facies suggests that some of the aberrations in brine composition might reflect the dissolution of

minerals other than the common evaporite phases of halite, anhydrite, and dolomite. Unfortunately, there are no known occurrences of any late-stage evaporite minerals in the Texas Panhandle. None were identified in petrographic (Handford and others, in preparation) and X-ray diffraction

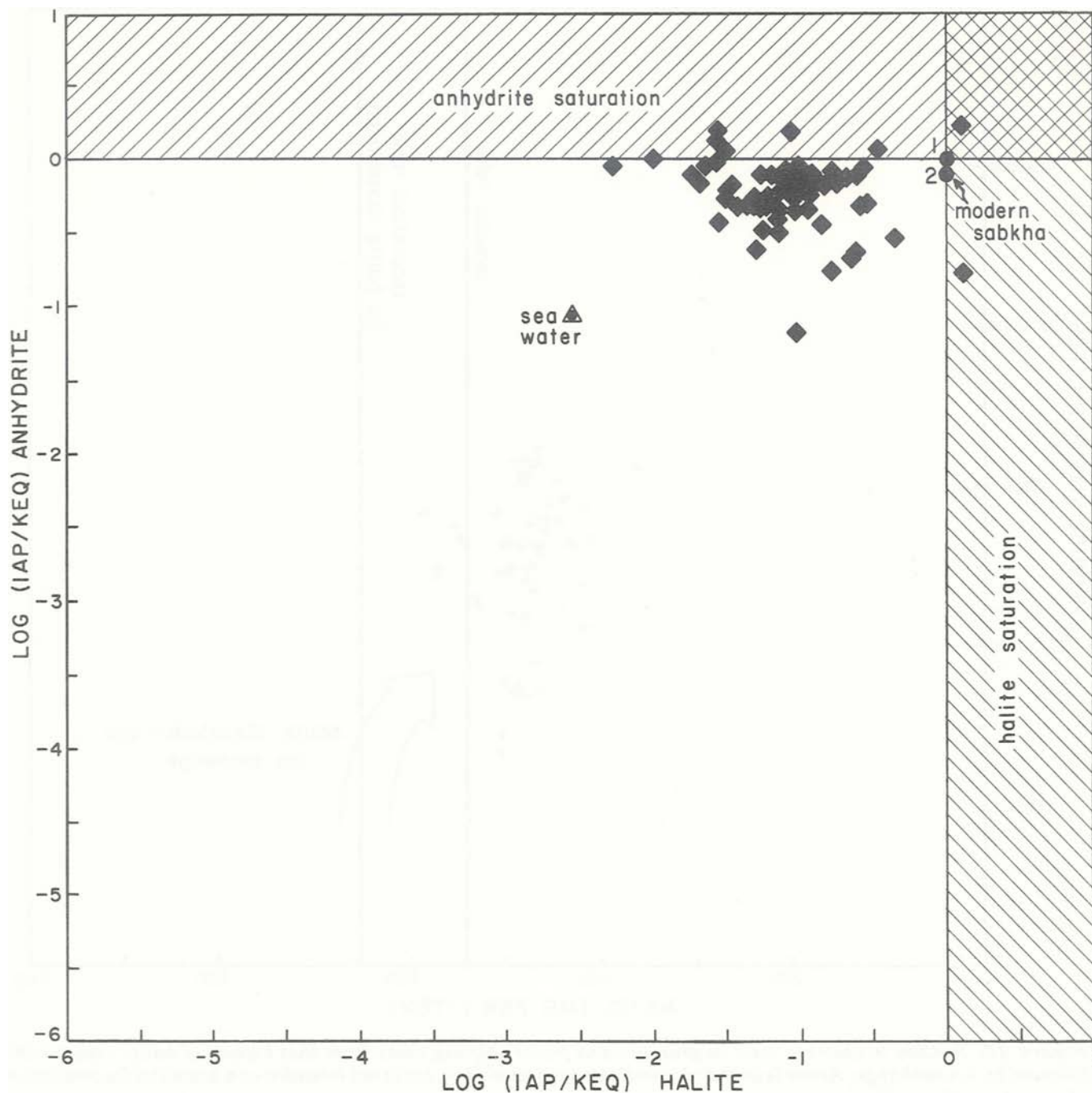


Figure 15. Saturation state of brine samples from Wolfcamp carbonate facies as computed with AQ/SALT.

(Bassett and Palmer, 1981) studies of 7,700 ft (2,369 m) of continuous core through the salt-bearing section. Potash has not been reported in the Palo Duro or Dalhart Basins; however, potash is mined in New Mexico in the southwestern part of the Permian Basin where the extent of Permian evaporation appears to have reached the stage of potash precipitation.

Thermodynamic Data and Computations

Equations have recently been formulated that describe ionic behavior in concentrated electrolyte solutions. The fundamental expression by Debye and Hückel (1923) and subsequent extensions

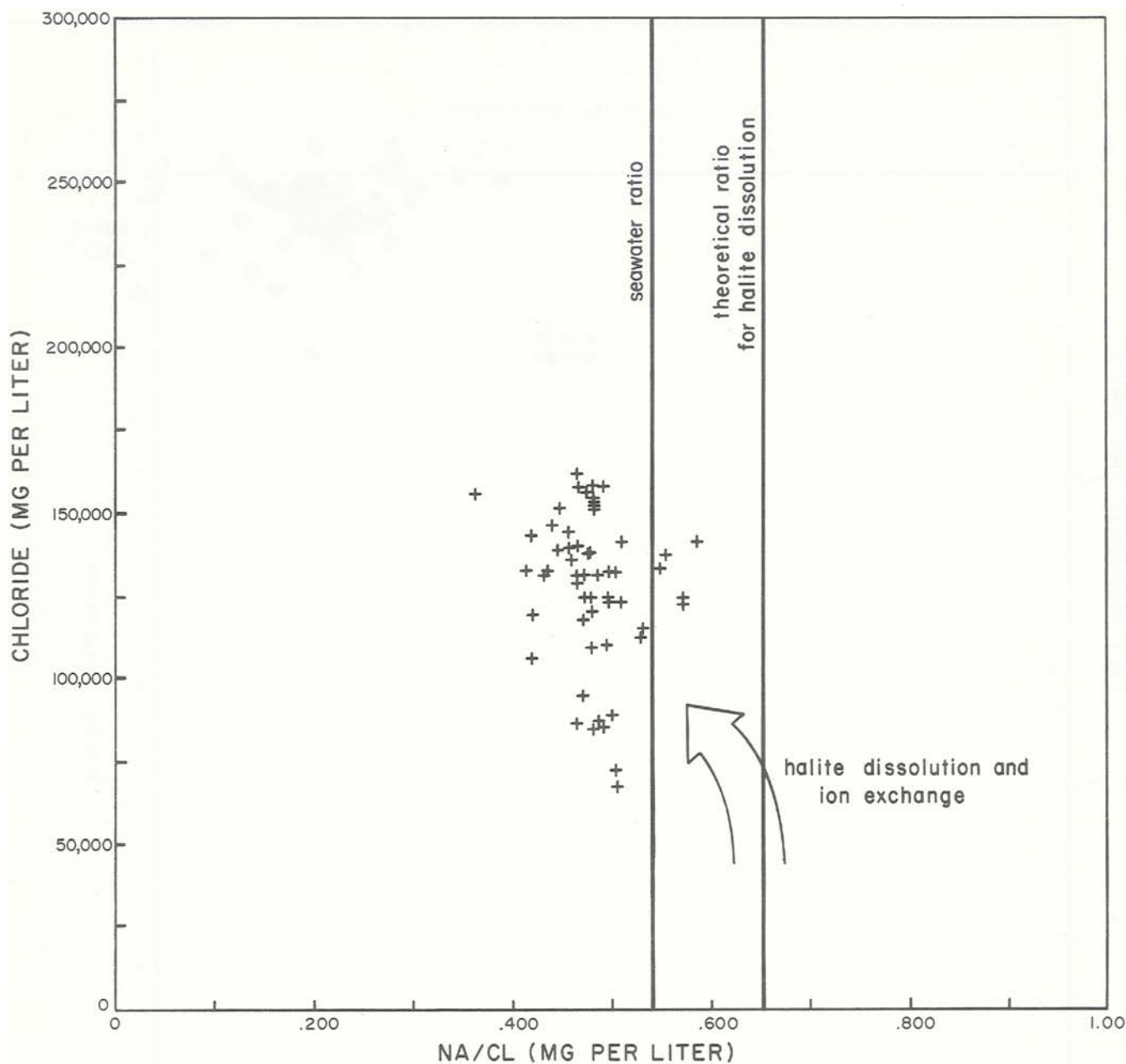


Figure 16. Sodium to chloride ratio in granite-wash facies shifting away from that typical of halite dissolution, followed by ion exchange. Arrow is included to indicate suspected shift, but is not intended as a quantitative prediction of actual reaction path.

have not performed adequately in the evaluation of concentrated brines, or in the investigation of solubilities of highly soluble minerals. The lack of an accurate mathematical model of short-range interionic forces in the computation of potentials apparently has been a major source of the deviation from experimentally obtained data. Pitzer (1979), Scatchard (1968), and others have

developed a rigorous and comprehensive theory for electrolyte solutions that can be approximated by a series of semiempirical equations. The equations, although somewhat cumbersome, especially for mixed electrolyte systems, can be quickly processed by the computer.

A rigorous test of Pitzer's (1979) equations to model mineral solubilities has been conducted by

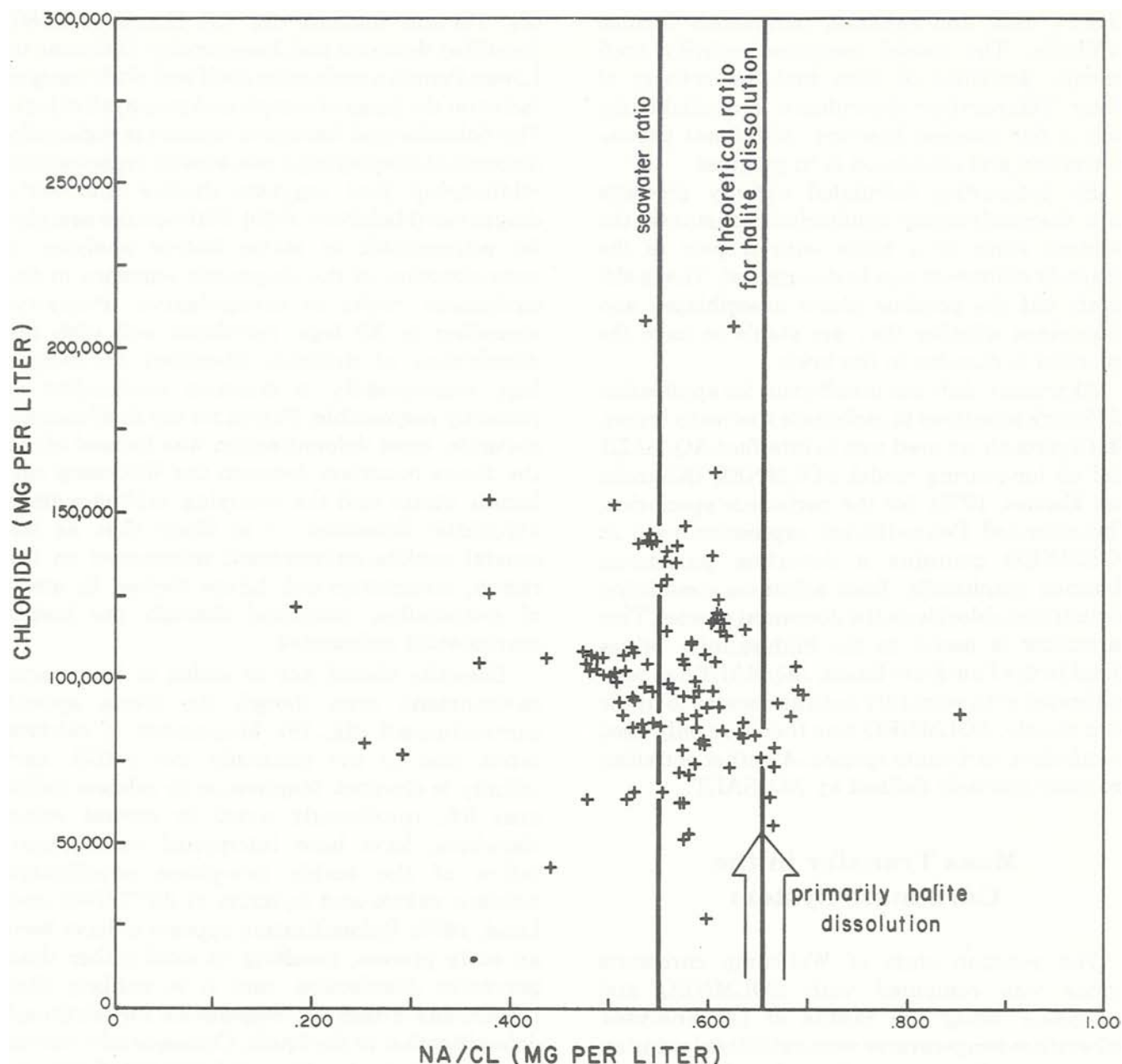


Figure 17. Sodium to chloride ratio in brine samples from Wolfcamp carbonates. Salinity is derived primarily from the overlying evaporites and from evaporite dissolution early in the flow path. Arrows are included to indicate suspected shift, but are not intended as a quantitative prediction of the actual reaction path.

Harvie and Weare (1980). Their results agreed with published solubility data. Harvie and others (1980) used free energy minimization to compute mineral sequences observed in the Permian Zechstein evaporites.

The computer model AQ/SALT has been developed for applications in studies of radioactive waste disposal and the geochemistry of deep

formation brines. The model employs the computationally more appropriate revision of Pitzer's equations by Harvie and Weare (1980). The model, discussed in more detail elsewhere (Bassett and Griffin, in preparation), will be only briefly mentioned here. AQ/SALT is a table-driven program that can accommodate any number of species and can be readily expanded

as new data and equation parameters become available. The model computes activity coefficients, activities of ions, and the activity of water. Temperature dependence is available for only a few species; however, additional parameterization and expansion is in progress.

By comparing calculated activity products with thermodynamic equilibrium constants, the reaction state of a brine with respect to the minerals of interest can be determined. The model prints out the possible phase assemblages and determines whether they are stable or have the potential to dissolve in the brine.

At present, data are insufficient for application of Pitzer's equations to carbonate species in brines. The approach we used was to interface AQ/SALT and an ion-pairing model, SOLMNEQ (Kharaka and Barnes, 1973), for the carbonate speciation. The extended Debye-Hückel expression used in SOLMNEQ contains a deviation parameter obtained empirically from solutions containing sodium and chloride as the dominant species. This parameter is useful in the high-salinity brines found in the Palo Duro Basin. AQ/SALT has been calibrated with solubility data and seems to fit the data closely. SOLMNEQ was therefore only used to calculate carbonate species. All other activities are more precisely defined by AQ/SALT.

Mass Transfer in the Carbonate System

The reaction state of Wolfcamp carbonate brines was computed with SOLMNEQ and AQ/SALT using the results of 121 analyses. Subsurface temperatures were calculated using an average geothermal gradient for the basin of 0.611°C/100 ft (Dutton, 1980). Depth was computed to the midpoint of the reported packer depths. All analyses were received in units of mg/L; consequently, a density correction was required to convert to units of molality. Density is computed assuming that brine weight is equal to the same equivalents of sodium chloride. Of the 121 Wolfcamp carbonate analyses, only 91 had a reported pH value; for the initial computations, only these analyses were processed.

Given the previous assumptions, the models indicate that almost all Wolfcamp carbonate brines are supersaturated with respect to calcite

(fig. 18) and dolomite (fig. 19). Handford (1980) identified dolomite and low-porosity limestone in Lower Permian carbonate shelf and shelf-margin facies on the basis of sample and geophysical logs. The dolomite and limestone contact is regionally discordant, displaying a non-stratal, cross-cutting relationship that suggests shallow and early diagenesis (Handford, 1980). Without core samples for petrographic or stable isotope analyses, a reconstruction of the diagenetic sequence in the carbonate rocks is inconclusive. Porosity, according to SP logs, correlates well with the distribution of dolomite identified on sample logs; consequently, a common mechanism is probably responsible. Except for the shelf-margin dolomite, most dolomitization was focused along the facies boundary between the Wolfcamp carbonate strata and the overlying sabkha-margin anhydritic dolomites. It is likely that as the coastal sabkha environment encroached on the region, magnesium-rich brines formed in areas of evaporation circulated through the buried marine-shelf carbonates.

Dolomite should not be stable in its present environment, even though the brines appear supersaturated (fig. 19). Magnesium to calcium ratios (mg/L) are generally low (<0.3), and salinity is elevated. Magnesium to calcium ratios near 0.5, consistently noted in ground water elsewhere, have been interpreted as representative of the stable two-phase equilibrium between calcite and dolomite at 25°C (Folk and Land, 1975). Dolomitization appears to have been an early process, resulting in local rather than pervasive distribution, and it is unlikely that present-day brines are responsible for continued dolomitization in the basin. Consequently, calcite solubility may be the predominant factor in determining carbonate mass transfer in this brine system.

Outgassing of carbon dioxide at the surface during sample collection is undoubtedly the cause of the apparent supersaturation with respect to carbonate minerals. Two approaches were taken to estimate the in situ partial pressure of carbon dioxide (P_{CO_2}) and to determine if calcite was in equilibrium with the brine. The first approach was to seek an analogy between in situ brine P_{CO_2} and the P_{CO_2} in natural gas from nearby producing fields. Second, a mass transfer approach was used, requiring a computer equilibrium model to

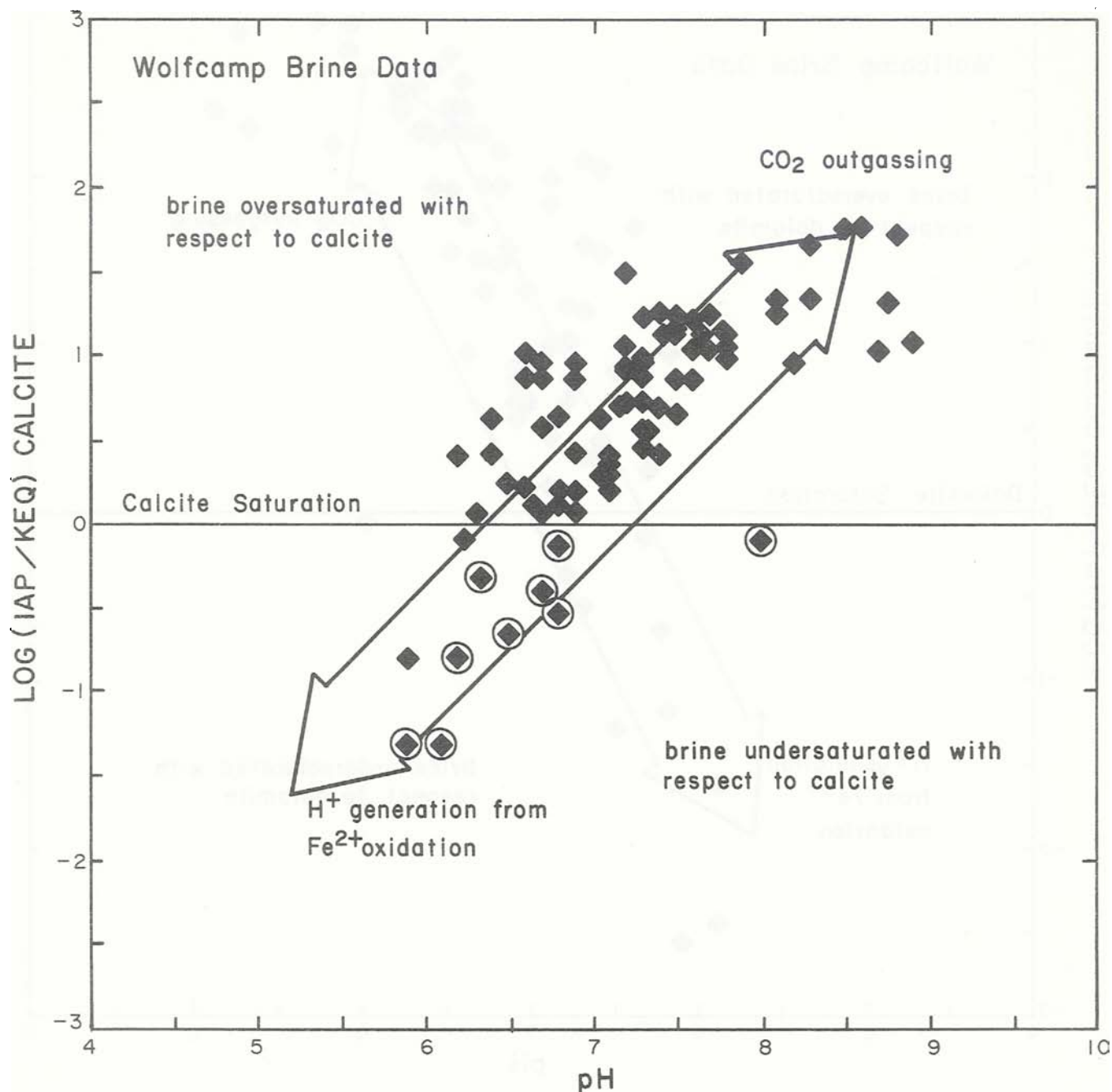


Figure 18. Saturation states computed with AQ/SALT and SOLMNEQ for Wolfcamp carbonate brines, the effect of outgassing of CO_2 , and the oxidation of dissolved iron. Circled data points represent compositions of fluid from Sherman County.

simulate the stepwise addition of CO_2 back into the sample. The variation in speciation was monitored along the reaction path, and a new in situ pH and P_{CO_2} were computed at the calcite phase boundary.

The Bureau of Mines (U.S. Department of Interior) surveyed worldwide helium potential from 1917 to 1974 by analyzing natural gas samples from 37 states and 23 foreign countries. Numerous oil and gas fields from the Texas

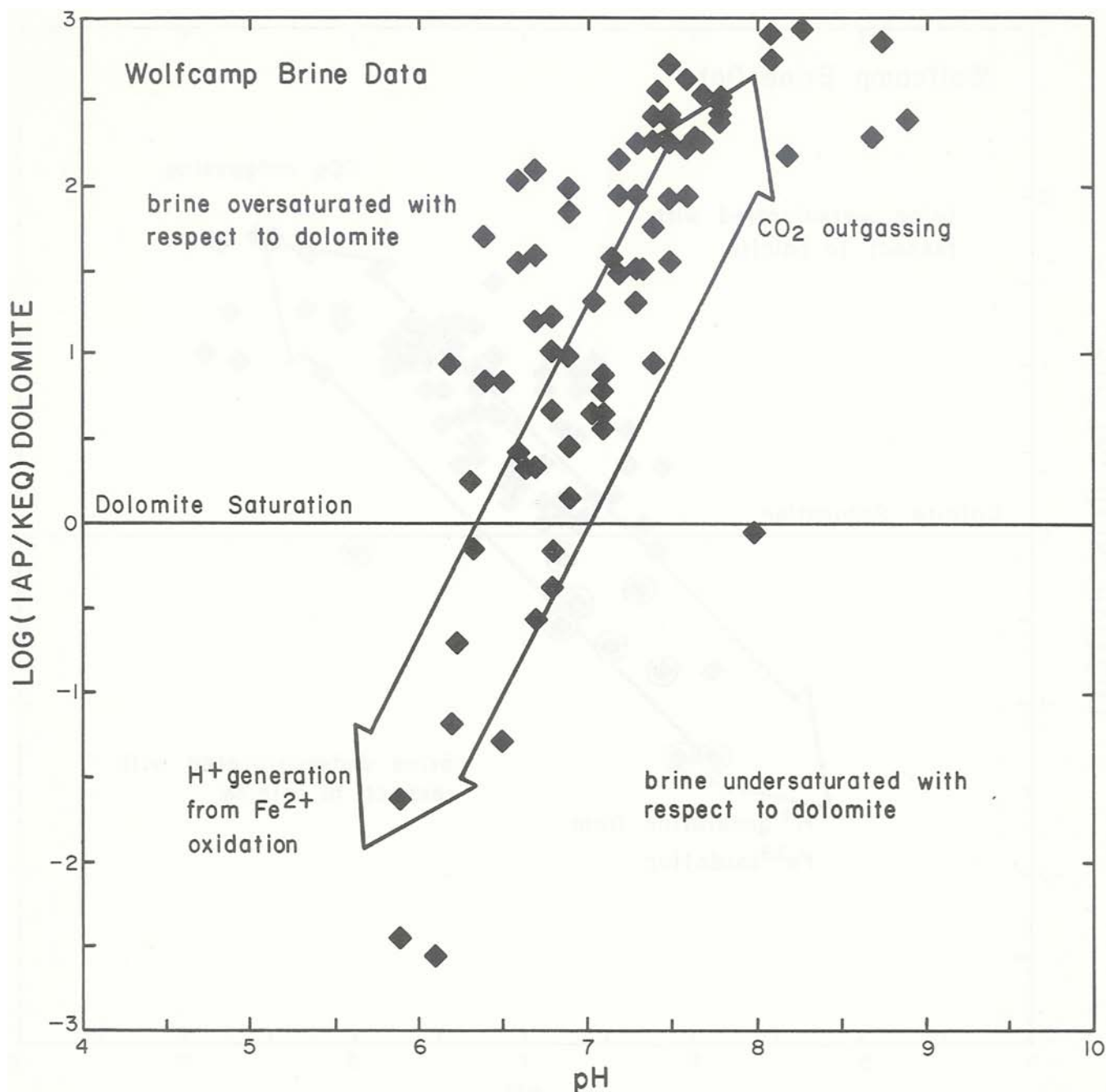


Figure 19. Saturation state of Wolfcamp carbonate brine with respect to dolomite as computed with AQ/SALT and SOLMNEQ.

Panhandle were included in this study (Moore, 1976). Data on wellhead pressures, depth, and mole percent CO_2 from Moore (1976) were used to compute a field P_{CO_2} (atm). Even though substantial variation in wellhead pressures exists among the producing fields, the P_{CO_2} across the region is defined within a relatively narrow range (fig. 20). Without stable isotope data, we assume

that the CO_2 is derived from within the basin during hydrocarbon maturation. The fields are too deep to be associated with biogenic methane (Hunt, 1979), and there is certainly no evidence of carbonate decomposition attending volcanic intrusion. It seems doubtful that CO_2 pressures would be so uniform across the basin (figs. 9 and 20) were there not some buffering mechanism. We

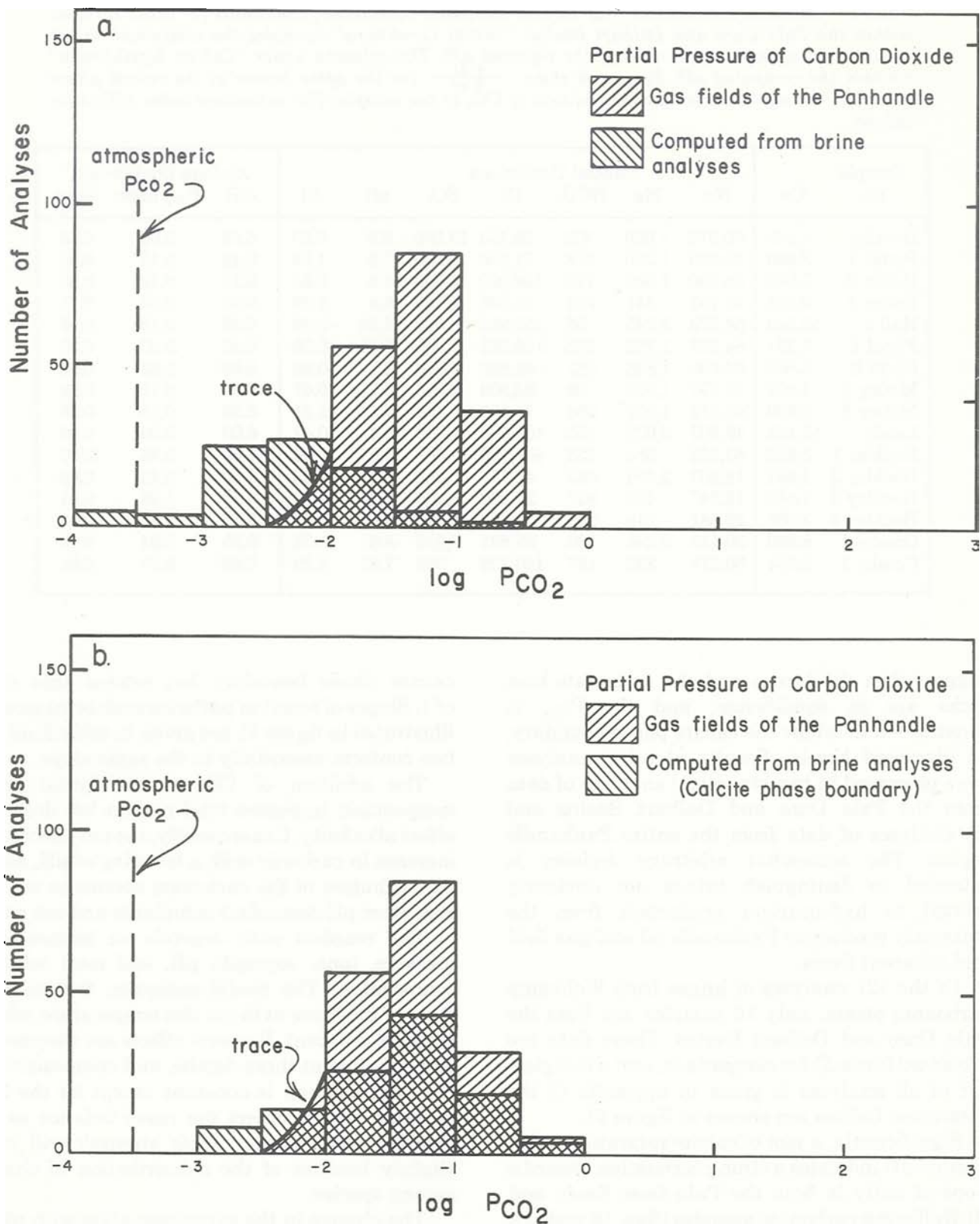


Figure 20. Distribution of CO_2 partial pressure in oil and gas fields in the Palo Duro and Dalhart Basins. Also shown is the distribution of $\log P_{CO_2}$ computed with (a) the reported pH and (b) the computed pH at the calcite phase boundary.

Table 2. Chemical composition (mg/L) and computed equilibrium conditions for brine samples within the Palo Duro and Dalhart Basins. "Initial Conditions" connotes the analytical values obtained from industry, including the reported pH. The columns under "Calcite Equilibrium" contain the computed pH, P_{CO_2} , and slope $\frac{\partial SI}{\partial pH}$ for the same brines at the calcite phase boundary owing to the simulated addition of CO_2 to the sample. The saturation index (SI) is for calcite.

Sample no.	Ca	Initial Conditions							Calcite Equilibrium		
		Na	Mg	HCO ₃	Cl	SO ₄	pH	SI	pH	P_{CO_2} (atm)	Slope
Hartley	1,100	60,310	1,069	302	88,154	13,090	6.8	0.20	6.59	0.09	0.96
Potter 1	3,660	40,900	1,350	278	71,600	2,350	7.9	1.56	6.19	0.15	0.91
Potter 2	7,960	56,200	1,540	173	104,000	1,600	6.8	0.64	6.15	0.10	0.98
Potter 3	6,578	47,193	841	106	85,566	1,735	8.0	1.69	6.40	0.03	0.71
Hall 1	32,340	58,579	2,245	56	153,982	517	6.24	-0.09	6.30	0.15	0.96
Floyd 1	6,234	84,667	1,782	132	146,281	1,035	6.32	0.06	6.26	0.07	0.95
Floyd 2	5,560	34,600	1,848	581	65,600	3,640	6.7	0.96	5.80	0.62	0.99
Motley 1	4,927	33,177	1,933	99	63,800	2,350	6.7	0.07	6.63	0.15	0.98
Motley 3	3,920	46,112	1,972	296	71,050	1,450	7.5	1.21	6.20	0.15	0.96
Lamb	15,120	46,607	3,072	195	106,500	1,700	6.4	0.42	6.00	0.09	0.99
Hockley 1	3,823	83,135	884	333	137,190	588	6.9	0.96	5.80	0.56	0.95
Hockley 2	4,687	18,907	2,534	652	42,777	2,252	6.4	0.63	5.80	0.43	0.99
Hockley 3	1,840	16,347	488	927	27,300	3,400	7.2	1.50	5.70	1.28	0.97
Hockley 4	3,286	29,581	648	801	51,304	2,120	6.6	1.02	5.70	0.91	0.98
Crosby 1	6,880	30,143	2,246	139	62,891	2,913	8.6	1.76	6.35	0.04	0.79
Crosby 2	8,164	80,271	992	187	140,729	365	7.31	1.23	6.00	0.15	0.94

suggest that the brines and the carbonate host rocks are in equilibrium, and the P_{CO_2} is constrained to follow the calcite phase boundary, as discussed herein. Results of brine analyses were processed in two stages: (1) analyses of data from the Palo Duro and Dalhart Basins and (2) analyses of data from the entire Panhandle region. The somewhat arbitrary division is intended to distinguish brines not obviously related to hydrocarbon production from the extremely productive Panhandle oil and gas field and adjacent fields.

Of the 121 analyses of brines from Wolfcamp carbonate strata, only 16 samples are from the Palo Duro and Dalhart Basins. These data are tabulated (table 2) for comparison, and a complete list of all analyses is given in appendix C; the saturation indices are shown in figure 21.

Significantly, a plot of calcite saturation index against pH indicates a strong correlation toward a slope of unity in both the Palo Duro Basin and all Wolfcamp carbonate samples (figs. 18 and 21). The stepwise addition of CO_2 to the solution with recalculation of pH, speciation, and saturation state moves the computed saturation toward the

calcite phase boundary but retains this slope of 1. Slopes of reaction paths for each brine sample illustrated in figure 21 are given in table 2; all but two conform essentially to the same slope.

The addition of CO_2 to the initial brine composition increases total carbon but does not affect alkalinity. Consequently, the net effect is an increase in carbonic acid, a lowering of pH, and a redistribution of the carbonate species as well as any other pH-dependent complexes and ion pairs.

The reaction path depends on temperature, pressure, ionic strength, pH, and total solution composition. The model computes the reaction state of the brine at the in situ temperature, which remains constant. Pressure effects are assumed to be negligible at these depths, and composition of the total solution is constant except for the CO_2 increase, which enters the mass balance as increasing total carbon. Ionic strength will alter slightly because of the redistribution of charge among species.

The change in the saturation state with pH is simply the derivative of the activity product minus the equilibrium constant with pH at constant temperature and pressure (T, P):

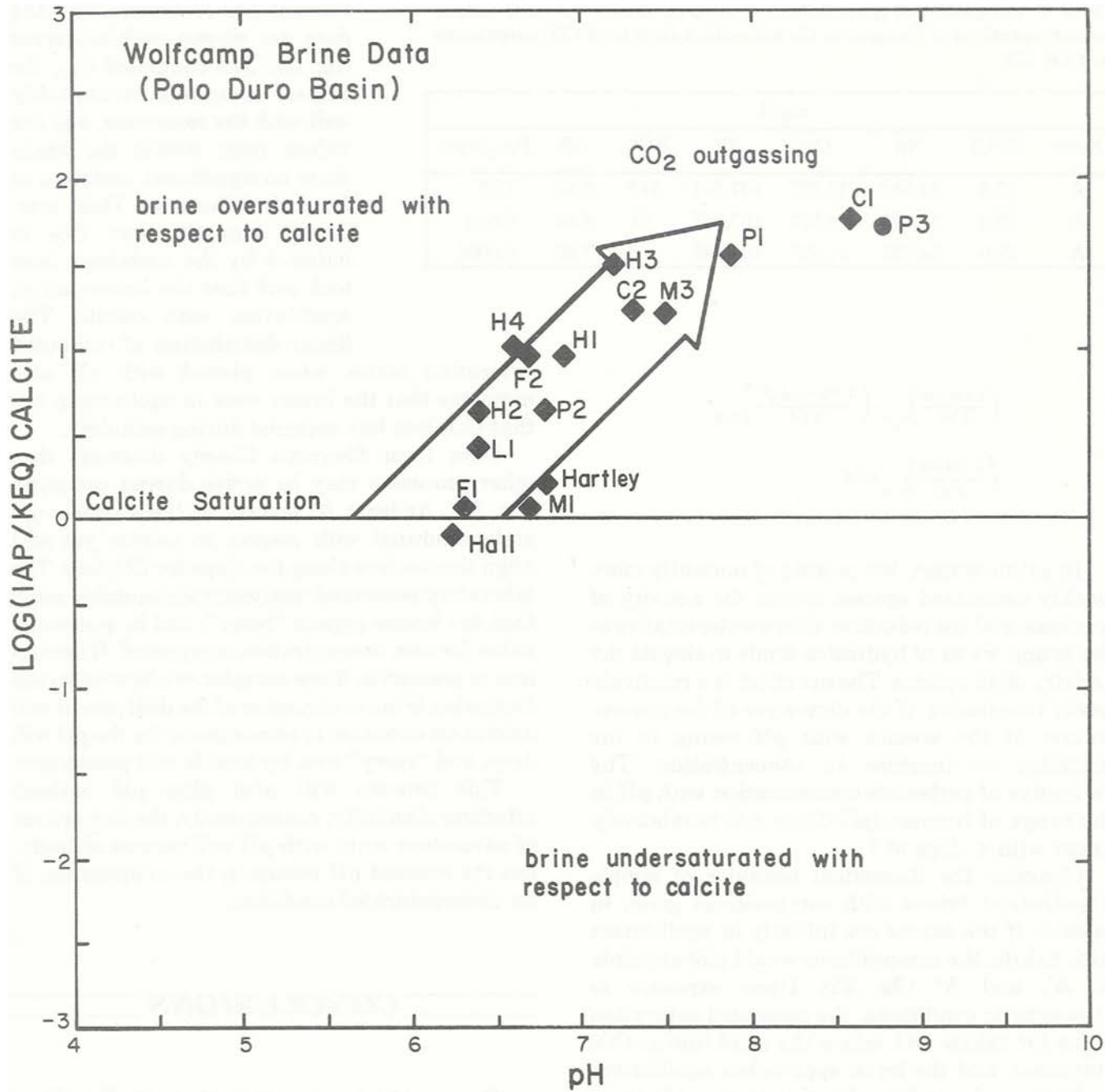


Figure 21. Computed saturation states for brines within the Palo Duro and Dalhart Basins using the reported pH values. For identification of data points, see table 2.

$$\left(\frac{\partial (\log \text{IAP} - \log \text{Keq})}{\partial \text{pH}} \right)_{T,P} = \left(\frac{\partial \log \text{IAP}}{\partial \text{pH}} \right)_{T,P}$$

Inserting the activity product for calcite,

$$\begin{aligned} \left(\frac{\partial \log \text{IAP}}{\partial \text{pH}} \right)_{T,P} &= \left(\frac{\partial \log (a_{\text{Ca}^{2+}} \cdot a_{\text{CO}_3^{2-}})}{\partial \text{pH}} \right)_{T,P} \\ &= \left(\frac{\partial \log (\gamma_{\text{Ca}^{2+}} \cdot m_{\text{Ca}^{2+}} \cdot \gamma_{\text{CO}_3^{2-}} \cdot m_{\text{CO}_3^{2-}})}{\partial \text{pH}} \right)_{T,P} \end{aligned}$$

Ionic strength changes are negligible, temperature and solution composition remain constant, and the change in ion pairing with pH over the range of interest does not alter the concentration of free calcium significantly. Consequently,

Table 3. Compositions of hypothetical brine in equilibrium with calcite for computations of changes in the saturation state with CO₂ outgassing (see fig. 22).

Brine	T(°C)	mg/L					
		Na	Ca	Cl	HCO ₃	pH	P _{CO₂} (atm)
A	37.6	54,783	11,527	107,345	610	5.50	1.55
A	37.6	54,576	11,527	107,345	61	6.50	0.012
A	37.6	54,555	11,527	107,345	6	7.55	0.0001

$$\left(\frac{\partial \log \text{lap}}{\partial \text{pH}} \right)_{T, P} = \left(\frac{\partial \log m \text{CO}_3^{2-}}{\partial \text{pH}} \right)_{T, P}$$

$$\left(\frac{\partial \log \text{lap}}{\partial \text{pH}} \right)_{T, P} \approx 1.0$$

In saline waters, ion pairing of normally more weakly associated species lowers the activity of free ions, and the reduction of free water relative to the bound water of hydration tends to elevate the activity of all species. The net effect is a relatively linear translation of the derivative of the concentration of the species with pH owing to the reduction or increase in concentration. The derivative of carbonate concentration with pH in the range of interest (pH 6.0 to 8.5) is relatively linear with a slope of 1.

Consider the theoretical behavior of simple hypothetical brines with compositions given in table 3. If the brines are initially in equilibrium with calcite, the compositions would plot at points A, A', and A'' (fig. 22). Upon exposure to atmospheric conditions, the computed saturation index for calcite will follow the solid line as CO₂ outgasses and the brine approaches equilibrium with atmospheric P_{CO₂}. If precipitation of calcite occurs, then the saturation index will decrease with a slope equivalent to the dashed line as acidity increases with deprotonation of bicarbonate. The pH values reported by industry appear to have been taken before calcite precipitation, resulting in the linear alignment of computed saturation indices with a slope of unity.

All Wolfcamp carbonate brine analyses from the Panhandle were translated to the calcite phase boundary by CO₂ addition. The equilibrium P_{CO₂} over these solutions was compared with that of

natural gas reservoirs, and the data are shown as histograms (fig. 20). The computed P_{CO₂} for brines compares remarkably well with the reservoirs, and the values from within the basin show no significant variation in P_{CO₂} distribution. This similarity suggests that CO₂ is buffered by the carbonate host rock and that the brines are in equilibrium with calcite. The linear distribution of computed

saturation states when plotted with pH also indicates that the brines were in equilibrium but that CO₂ loss has occurred during sampling.

Data from Sherman County illustrate that other processes may be active during sampling (fig. 23). At least 30 percent of the samples are undersaturated with respect to calcite, yet still align themselves along the slope for CO₂ loss. The laboratory personnel analyzing the samples noted that the brines appear "rusty"; and in general, a value for iron concentration is reported. If ferrous iron is present in these samples, whether from the formation brine or corrosion of the drill pipe, it will oxidize on exposure to atmospheric O₂, the pH will drop, and "rusty" iron hydroxide will precipitate.

This process will also alter pH without affecting alkalinity; consequently, the derivatives of saturation state with pH will remain at unity, but the lowered pH results in the computation of an undersaturated condition.

CONCLUSIONS

Regional hydraulic gradients in the Palo Duro and Dalhart Basins indicate that the brines are moving eastward. The evaporite section acts as a low-permeability barrier above the transmissive carbonate and granite-wash facies. Owing to the elevated topography, the central part of the basin appears to be underpressured; however, the horizontal head gradients are comparable to the regional topographic slope.

The scarcity of oil and gas production in the basins enhances the attractiveness of these basins as potential nuclear waste repository sites;

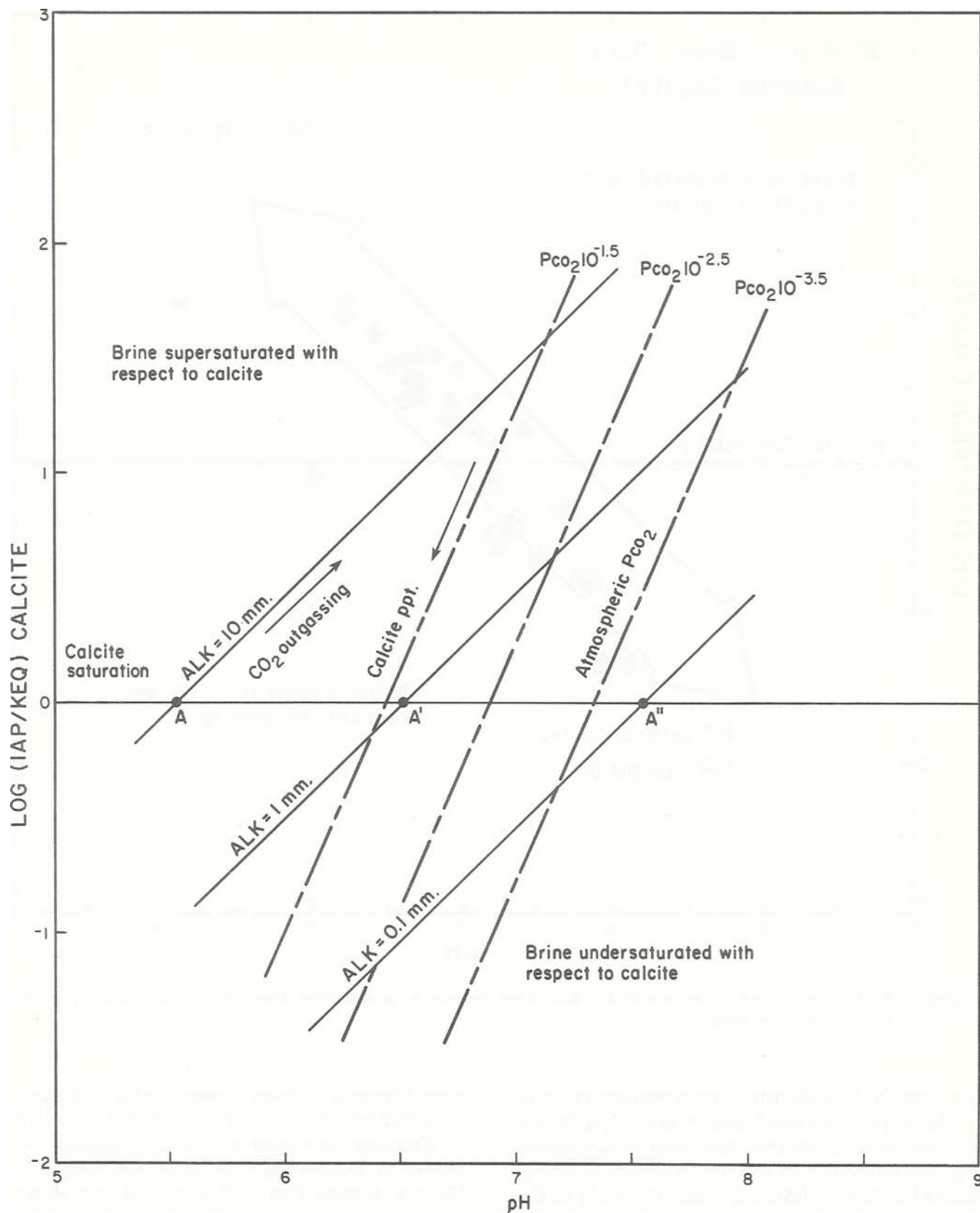


Figure 22. Theoretical behavior of the computed saturation index (SI) with respect to pH accompanying mass transfer of CO_2 . Solid lines illustrate path of the SI without calcite precipitation, whereas dashed lines indicate the reaction path commensurate with calcite precipitation after some degree of saturation is attained.

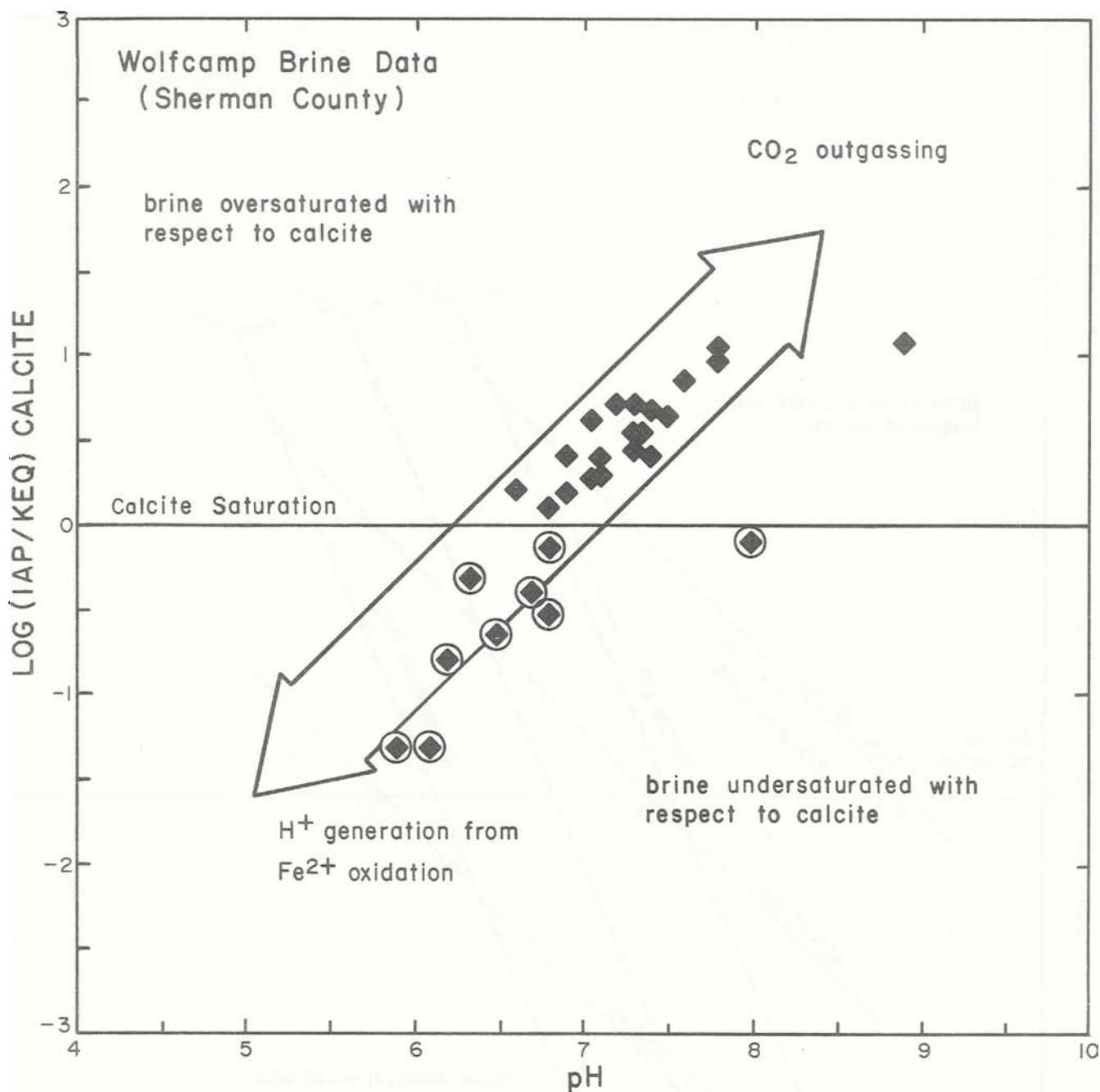


Figure 23. Computed saturation states for Wolfcamp carbonate brines from Sherman County, illustrating the effect of CO_2 loss and iron oxidation.

however, the lack of hydrocarbon resources results in a lack of data on the chemistry of the deep brines and formation pressures. Available data indicate regional similarity in salinity, which is probably derived from dissolution of evaporites early in the flow path. The basin system is hydraulically contiguous and may have been through-flowing

since the early Tertiary; consequently, as many as 50 to 60 pore volumes may have flushed the basins.

Recently developed computer programs were useful in evaluating the brine reaction state. Carbon dioxide loss and iron oxidation during sampling have altered pH values of the brine; however, a reconstruction of in situ P_{CO_2} indicates

that the brines are in equilibrium with the calcite in the carbonate host rocks. Wolfcamp carbonate brines appear to be following the anhydrite phase boundary; however, the granite-wash brines are not in equilibrium with anhydrite because of sulfate reduction.

Future exploratory drilling will be essential for properly collecting and preserving brine samples and obtaining pressure measurements in the most advantageous locations. It is encouraging that drill-stem-test pressure data and brine analyses from wildcat exploration programs are to some extent useful in interpreting the basin characteristics.

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APPENDIX A: Horner Plots for Wolfcamp Carbonates

The drill-stem-test charts received from operators in the Palo Duro Basin have been analyzed according to the Horner method (Horner, 1951). The equation described by Horner (equation 1) is an approximation of an exact solution for pressure changes in a single well in an infinite reservoir:

$$P_w = P_o - \frac{q \mu}{4\pi kh} \ln \frac{(t_o + Dt)}{Dt} \quad (1)$$

where h = thickness of the tested interval (ft)
 k = average permeability (md)
 P_o = undisturbed formation pressure (psi)
 P_w = pressure at the well bore (psi)
 q = rate of production

q_a = average rate of production in the previous flowing period (bbl/d)
 t_o = length of production time (hr)
 Dt = elapsed time since pressure build-up began after final production period (hr)
 μ = viscosity of the fluid (cp)

On conversion of equation 1 to standard units employed by the petroleum industry the expression becomes

$$P_w = P_o - \frac{162.6 q_a \mu}{kh} \log \frac{t_o + Dt}{Dt} \quad (2)$$

A semilog plot of the pressure data (P_w) against $\log [(t_o + Dt)/Dt]$ should approach a straight line after the early production effects have diminished. The slope (m) of the straight-line part of this plot is computed as

$$m = \frac{\Delta P_w}{\text{cycle of } \log (t_o + Dt)/Dt} \quad (3)$$

which reduces equation 2 to

$$k = \frac{162.6 q_a \mu}{mh} \quad (4)$$

Extrapolation of the straight line according to equation 5

$$\log \frac{t_o + Dt}{Dt} = 0 \quad (5)$$

will yield the estimated undisturbed formation pressure where P_w equals P_o .

The Horner plots shown in figures A1 through A19 summarize the available data for drill-stem tests in the Wolfcamp carbonates. Slope (m), correlation coefficient (r), number of points used for the extrapolation (n), and the extrapolated formation pressures (P_i and P_f) are tabulated for the initial shut-in pressure (ISIP) and final shut-in pressure test (FSIP), respectively. Equivalent fresh-water heads (H_{ISIP} , H_{FSIP}) have been computed for each extrapolated undisturbed formation pressure (P_o) by dividing by 0.433 psi/ft and correcting for elevation. Permeability was determined from equation 4 using the data from the Horner plot and information provided with the drill-stem-test chart obtained from the service company. These data are summarized in table A-1.

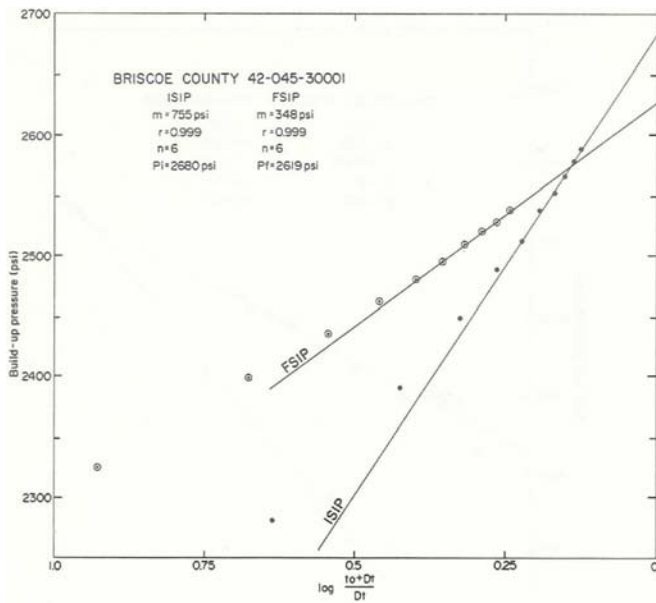


Figure A-1.

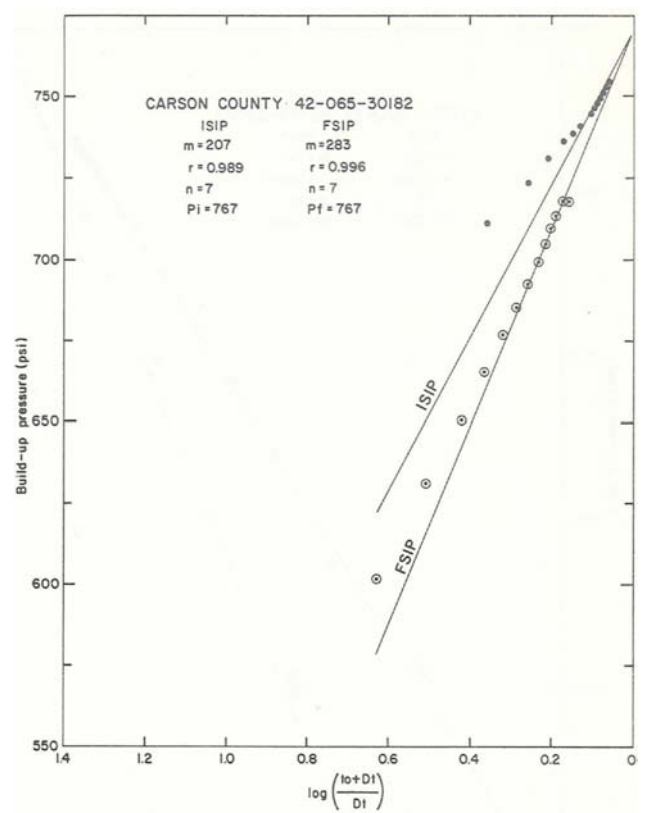


Figure A-2.

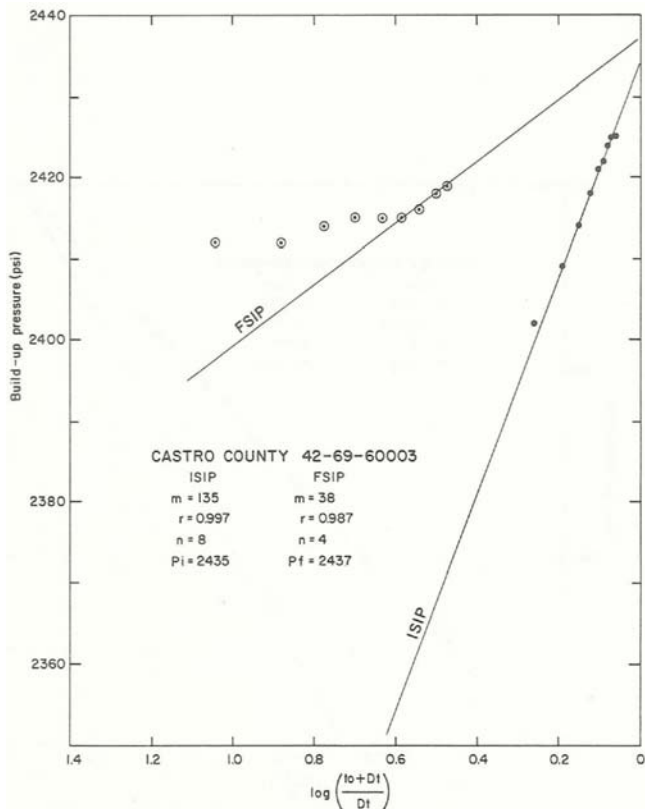


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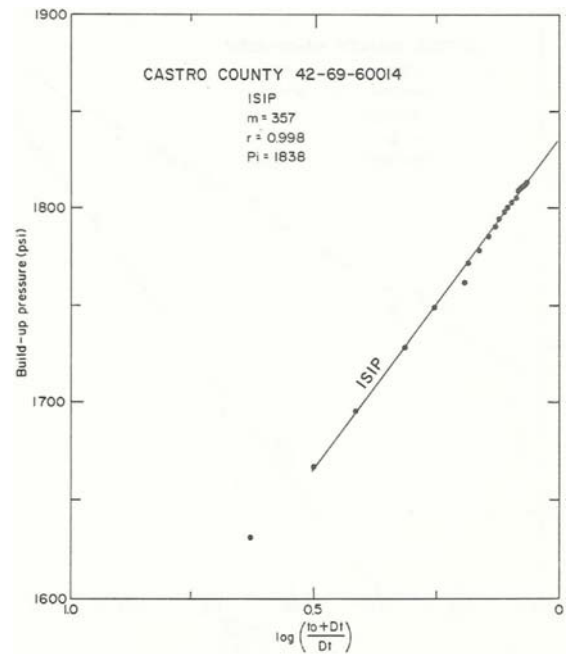


Figure A-4.

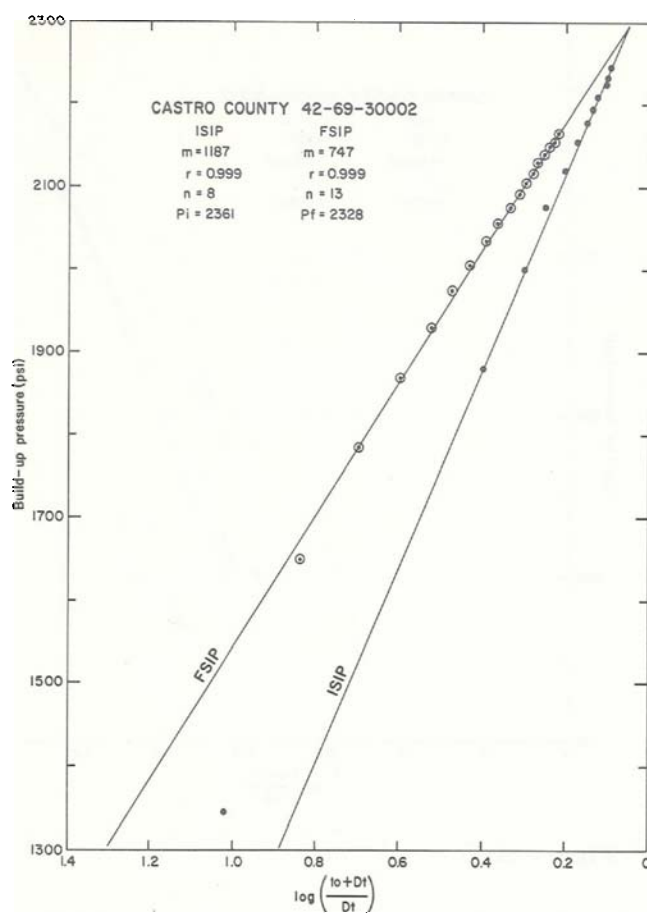


Figure A-5.

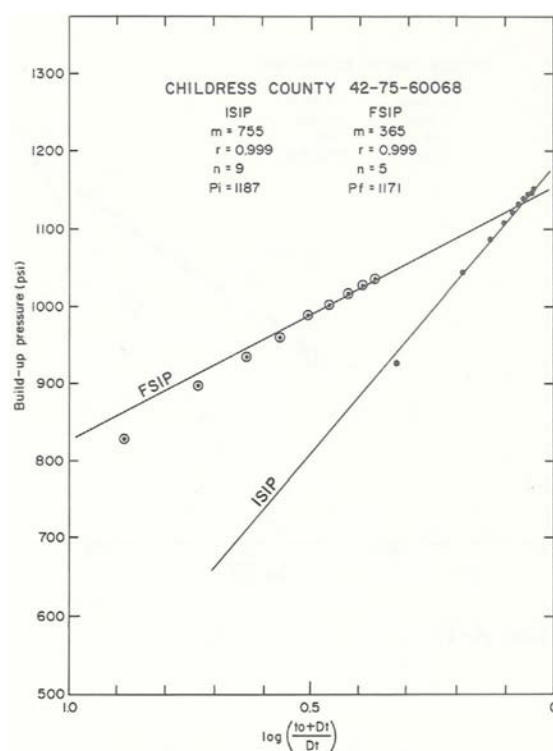


Figure A-6.

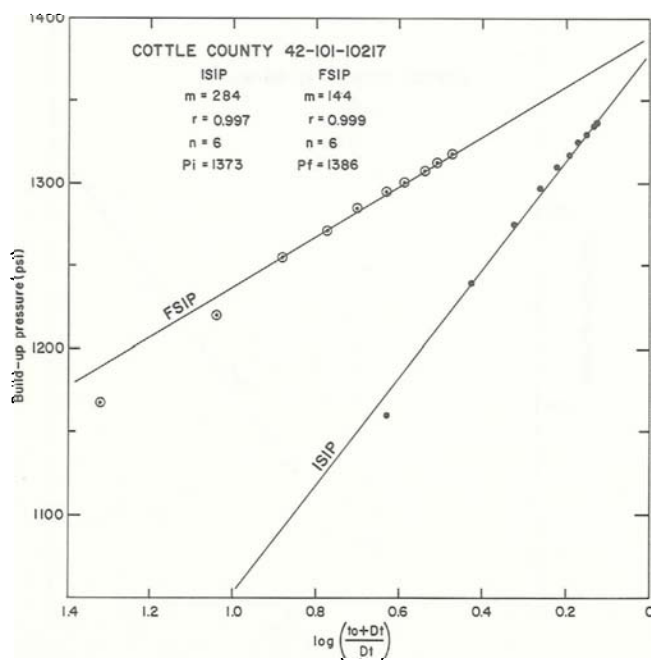


Figure A-7.

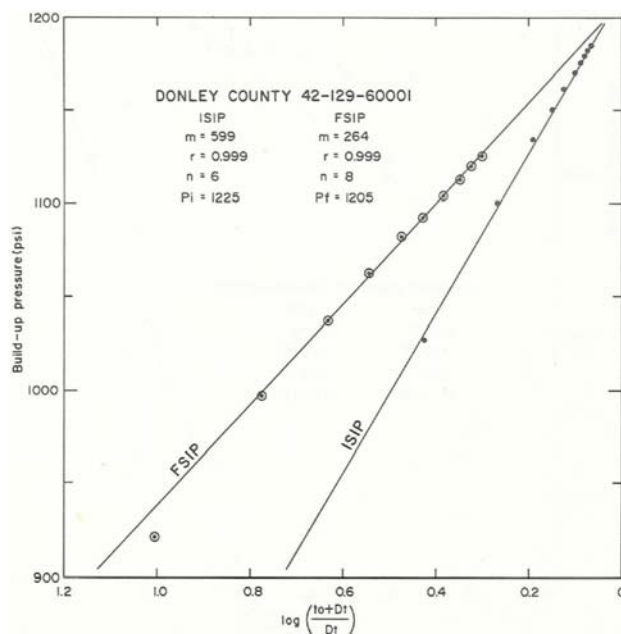


Figure A-8.

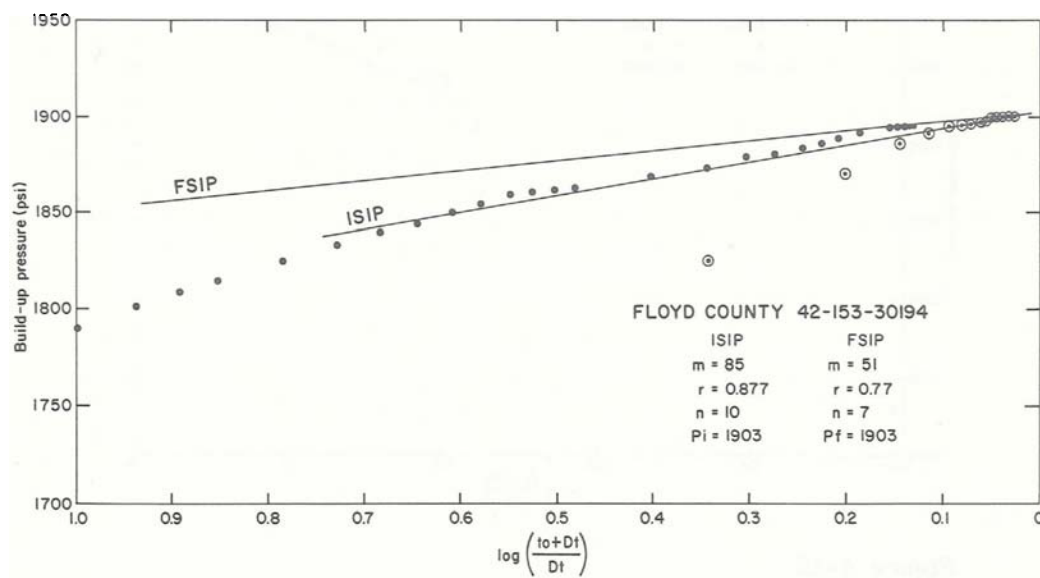


Figure A-9.

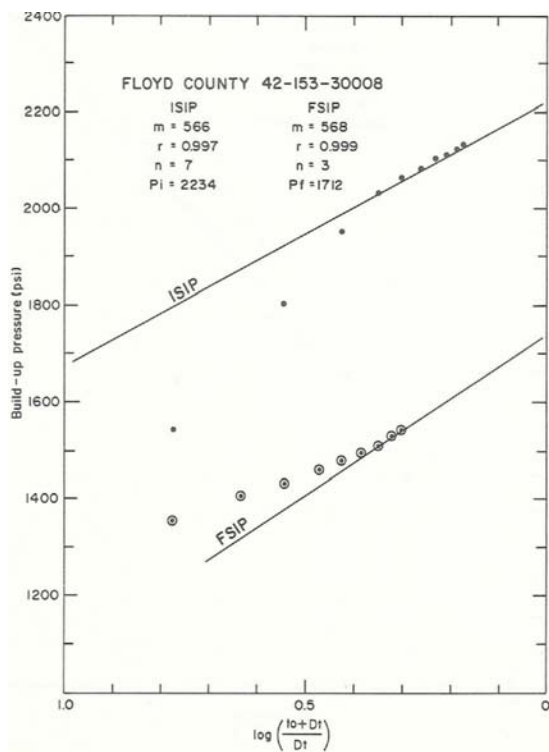


Figure A-10.

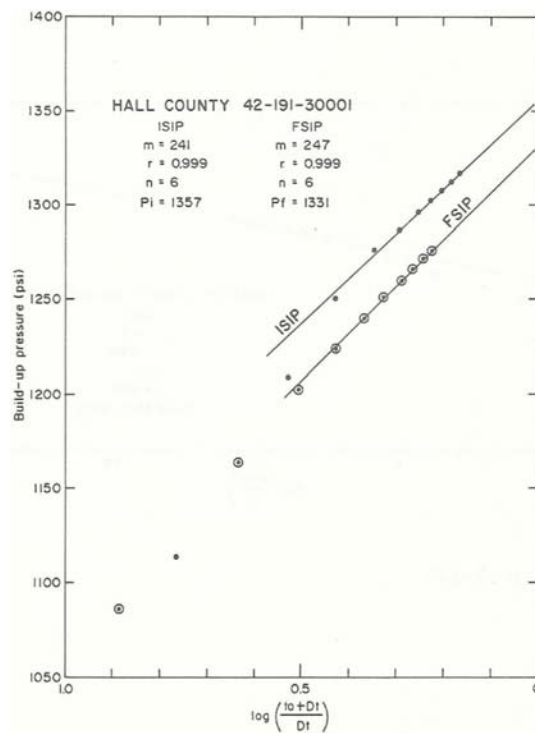


Figure A-11.

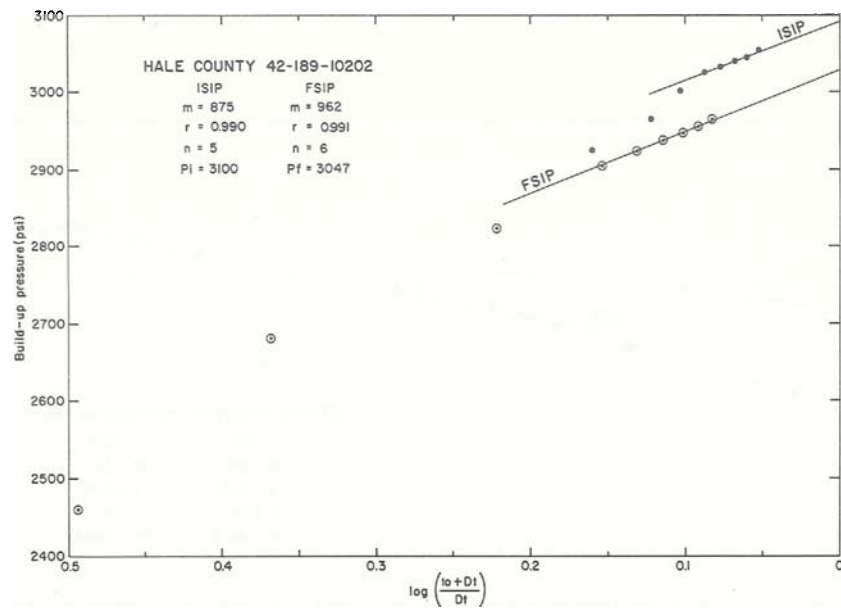


Figure A-12.

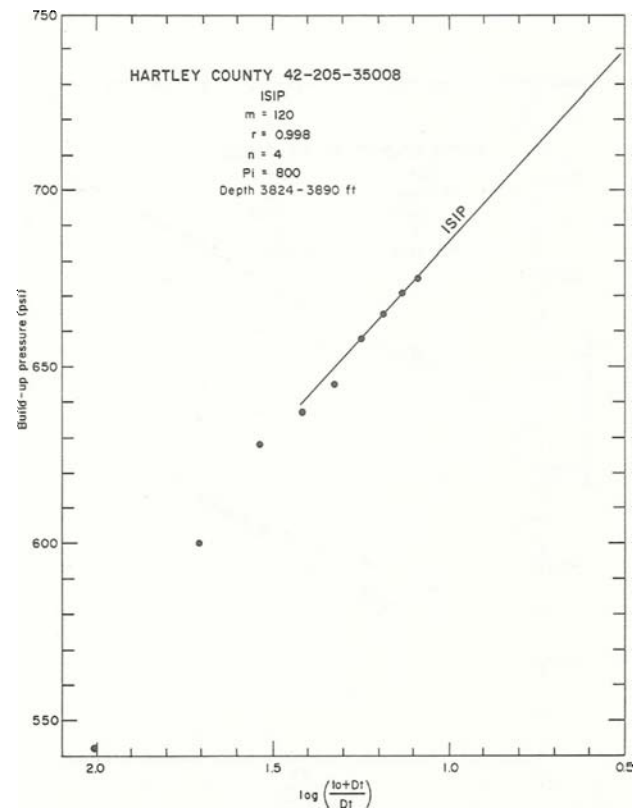
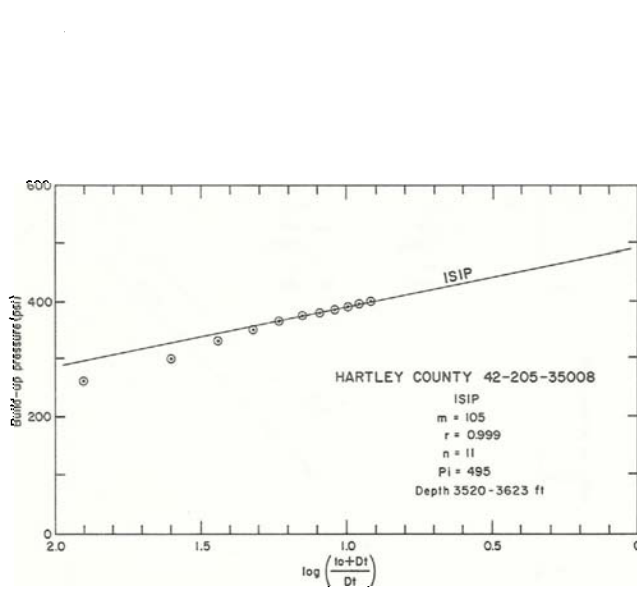


Figure A-13.

Figure A-14.

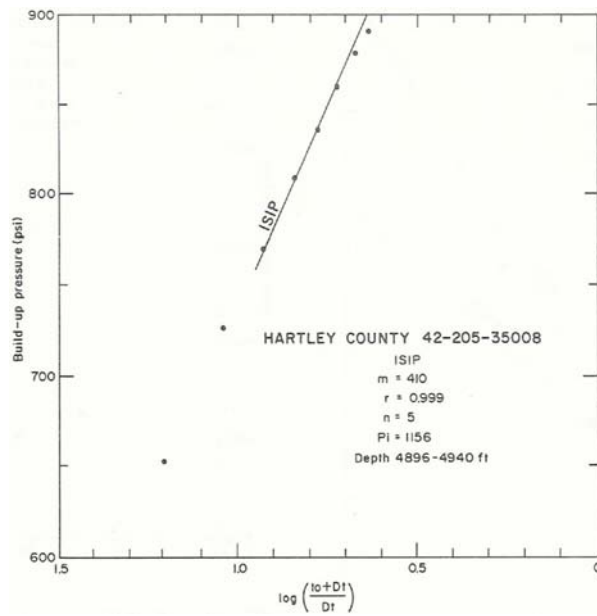


Figure A-15.

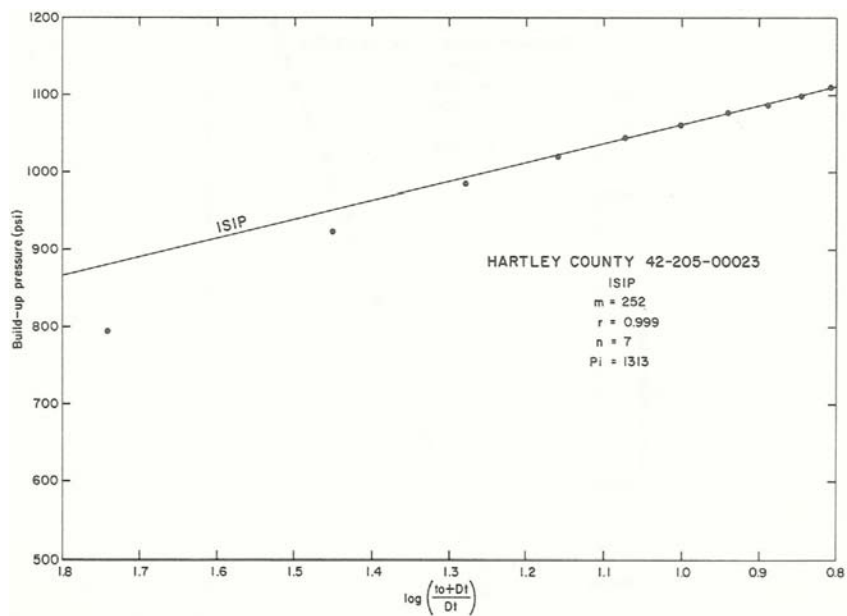


Figure A-16.

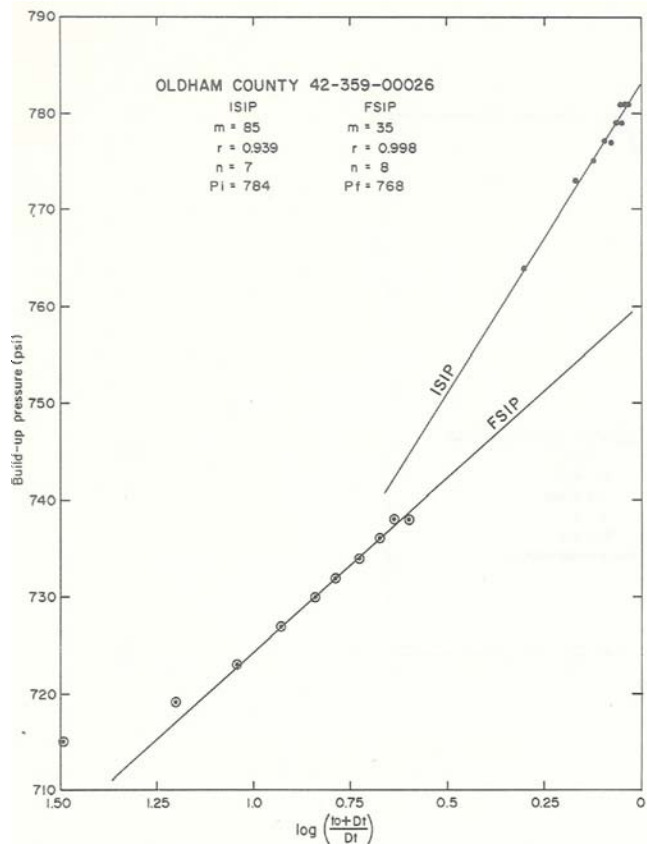


Figure A-17.

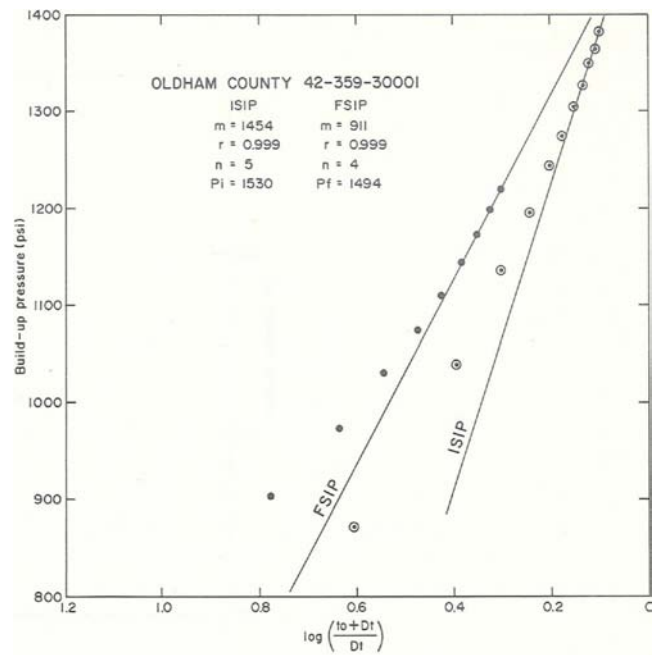


Figure A-18.

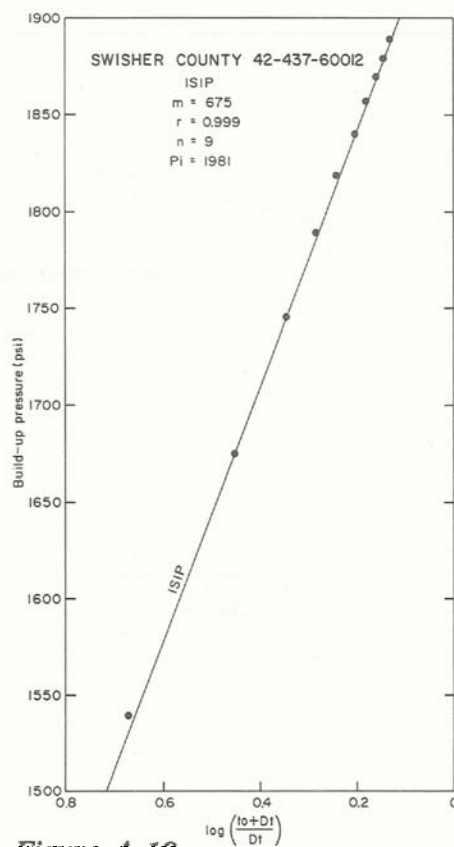


Figure A-19.

Table A-1. Hydraulic parameters derived from an analysis of drill-stem-test charts using the Horner method (1951). The selected permeability and hydraulic values are underscored in the table.

County	BEG well no.	Company	API no.	Depth tested (ft)	Thickness (ft)	K _{ISIP} (md)	K _{FSIP} (md)	H _{ISIP} (ft)	H _{FSIP} (ft)	Comments†††
Briscoe	21	Cockrell	42-045-30001	6,344-6,411	67	8.5	<u>1.31</u>	<u>3,105</u> †	<u>2,964</u> †	L. Wfc. shelf**
Carson	38	Shenandoah	42-065-30182	3,601-3,615	14	1.1	<u>0.24</u>	<u>1,551</u>	<u>1,551</u>	M. Wfc. back shelf**
Castro	1	Amarillo	42-069-60003	6,909-7,059	150	64.0	<u>26.0</u>	<u>2,500</u>	<u>2,505</u> ‡	M. Wfc. por. dol.
Castro	7	Union	42-069-60014	5,183-5,228	45	<u>6.0</u>	—	<u>2,750</u>	—	T. Wfc. sl. por. (sabk.)
Castro	7	Union	42-069-60014	5,838-5,932	94	***	***	<u>2,206</u>	<u>2,206</u>	M. Wfc. chalky ls.
Castro	10	Phillips	42-069-30002	6,762-6,782	20	0.36	<u>0.27</u>	<u>2,560</u>	<u>2,483</u>	U. Wfc. sl. por. dol. ls. (sabk.)
Childress	76	Westex	42-075-60068	2,633-2,663	30	0.95	<u>0.03</u>	<u>1,818</u>	<u>1,781</u>	U. Wfc. dol. and ls.**
Cottle	10	Murphy	42-101-10217	3,169-3,178	9	15.5	<u>8.8</u>	<u>1,867</u>	<u>1,897</u>	U. Wfc. sl. calc. dol. (sabk.)
Donley	31	Shell	42-129-60001	3,350-3,399	49	0.51	<u>0.79</u>	<u>1,797</u>	<u>1,754</u>	U. Wfc. por. ls. (sabk.)
Floyd	*	Amoco	42-153-30194	5,500-5,581	81	8.9	<u>8.3</u>	<u>2,081</u>	<u>2,081</u>	*
Floyd	*	Ken Pet.	42-153-30008	4,660-4,750	90	0.68	<u>0.59</u>	<u>3,597</u> ††	<u>2,392</u> ††	*
Hale	6	Mobil	42-189-10202	7,864-8,036	172	1.04	<u>0.1</u>	<u>2,583</u>	<u>2,461</u>	L. Wfc. sl. por. ls. (?) may be U. Penn.
Hall	*	Americas	42-191-30001	3,365-3,390	25	0.62	<u>0.44</u>	<u>1,890</u>	<u>1,830</u>	*
Hartley	13	Standard	42-205-35008	3,520-3,623	66	<u>0.77</u>	—	<u>1,381</u>	—	T. Wfc. an. dol. (sabk.)
Hartley	13	Standard	42-205-35008	3,824-3,890	66	<u>1.0</u>	—	<u>1,796</u>	—	U. Wfc. dol. ls. (sabk.)
Hartley	13	Standard	42-205-35008	4,896-4,940	44	<u>0.24</u>	—	<u>1,574</u>	—	L. Wfc. calc. ss.
Hartley	16	Standard	42-205-00023	3,916-3,957	41	<u>1.75</u>	—	<u>3,007</u>	—	U. Wfc. dol. ls. (sabk.)
***Lamb	*	Gulf	42-279-30045	7,352-7,404	52		***	<u>2,522</u>	<u>2,510</u>	*
***Motley	13	Mobil	42-345-00015	4,674-4,715	41		***	<u>1,950</u>	<u>1,947</u>	U. Wfc. dol. (sabk.)
Oldham	4	Shell	42-359-00026	3,446-3,471	25	27.0	<u>44.0</u>	<u>1,945</u>	<u>1,908</u>	U. Wfc. **
Oldham	48	Shell	42-359-30001	5,340-5,367	27	1.0	<u>0.6</u>	<u>1,824</u>	<u>1,741</u>	M. Wfc. ls.
***Potter	26	Rice	42-375-35013	3,907-4,050	143		***	<u>1,486</u>	—	T. Wfc. por. dol.
Swisher	8	Burdell	42-437-60012	5,765-5,796	31	<u>0.1</u>	—	<u>2,360</u>	—	U. Wfc. por. ls.

† The head values appear to be anomalously high compared with surrounding values; however, the test appears acceptable mechanically.

†† A 1,000-psi difference between ISIP and FSIP is not explainable at this time; the higher value is selected.

††† L. = lower, M. = mid, U. = upper, ls. = limestone, dol. = dolomite, por. = porous, sl. = slightly, T. = top, Wfc. = Wolfcamp, calc. = calcareous, sabk. = sabkha may have influenced dolomitization, Penn. = Pennsylvanian, an. = anhydritic.

* no log information **no sample log ***build-up test reached formation pressure; permeability cannot be computed; consequently an illustration of the data is not provided on the following pages.

— only one shut-in period.

APPENDIX B: Chemical Composition of Formation Brines

The chemical compositions of brines listed in the following tables were obtained from either the Petroleum Data System Brine file at the University of Oklahoma or from petroleum companies that forwarded these analyses to us along with additional information on drill-stem tests conducted in the Palo Duro Basin. None of the brines were collected or analyzed by the BEG; consequently, only standard industry procedures were employed during their collection.

Substantial outgassing of CO₂ has undoubtedly occurred during sampling (see text); thus, the reported pH is, in general, too high. As a result, the brines all compute to be supersaturated with respect to calcite. A computer simulation program

was used to compute a new pH for Wolfcamp brines, which represents the most likely in situ partial pressure of CO₂ at the calcite phase boundary. We suggest that this computed value is representative of the brine pH in the formation, and consequently we list this value with the analyses in the following tables as "pH_c." The constraints on the brine chemistry of granite-wash aquifers are less clear. Therefore, the computed values for pH are not listed, pending further investigation. Hydrologic test wells currently being drilled will provide the first brine samples collected by the BEG from the Permian and Pennsylvanian granite-wash aquifers.

The wells from which these samples were collected can be located by comparing the underlined TDS values on figures 10 and 11 with those listed in table B-1. Temperatures are computed using the average geothermal gradient for the region (0.611°C/100 ft).

Table B-1. Chemical composition of brines collected from wells penetrating the Wolfcamp deep-basin aquifer.

WOLFCAMP CARBONATES											
County	Depth (ft)	TDS (mg/L)	Temp (°C)	Reported pH	Ca (mg/L)	Na (mg/L)	Mg (mg/L)	HCO ₃ (mg/L)	Cl (mg/L)	SO ₄ (mg/L)	pH _c
Hartley	4,469-4,520	164,026	45.6	6.8	1,100	60,310	1,069	302	88,154	13,090	6.59
Potter	4,573-5,395	120,000	46.2	7.9	3,660	40,900	1,350	278	71,600	2,350	6.19
Potter	4,824-4,875	172,000	47.8	6.8	7,960	56,200	1,540	173	104,000	1,600	6.15
Potter	4,790	142,121	47.3	8.8	6,578	47,193	841	106	85,566	1,735	6.40
Moore	3,300-3,310	116,228	38.5	7.0	1,344	42,692	510	82	64,271	7,326	7.00
Moore	3,310-3,315	133,399	38.5	7.0	1,165	49,185	697	401	73,579	8,365	6.50
Moore	3,224	132,376	38.0	7.0	1,358	49,810	725	172	76,090	5,119	6.81
Moore	3,818	139,493	41.6	7.0	5,657	45,060	2,224	49	84,610	1,892	6.87
Moore	3,224	120,953	38.0	7.0	3,800	41,564	1,018	0	71,300	2,992	—
Moore	3,224	160,822	38.0	7.0	5,380	54,905	1,493	131	97,181	1,729	6.44
Moore	3,224	180,247	38.0	7.0	3,929	64,283	1,284	171	107,437	3,141	6.41
Moore	3,073-3,274	177,402	37.1	6.9	3,563	64,177	898	73	105,431	3,259	6.82
Moore	3,200	127,058	37.9	7.0	2,347	45,541	865	210	73,184	4,908	6.52
Moore	3,173	150,834	37.7	7.0	2,001	55,171	865	269	86,718	5,808	6.47
Moore	3,242	136,984	38.1	7.0	3,205	47,742	1,452	93	80,700	3,789	6.78
Wheeler	1,969-2,018	166,835	30.3	6.2	10,024	49,168	3,393	479	101,920	1,850	6.20
Hutchinson	2,600	154,115	34.2	7.0	3,183	54,512	1,425	237	90,877	3,881	6.40
Hutchinson	3,005	158,938	36.7	7.0	3,942	55,658	1,434	234	94,651	3,017	6.30
Hutchinson	3,040	156,592	36.9	7.0	2,811	56,243	1,167	273	91,839	4,256	6.35
Hutchinson	3,200	152,562	38.0	7.0	8,586	47,372	2,008	134	92,561	1,898	6.31
Hutchinson	3,200	174,353	37.9	7.3	10,870	52,144	2,874	121	106,614	1,728	6.30
Hutchinson	3,160	169,457	37.6	7.2	10,961	49,973	3,003	188	104,228	1,101	6.11
Hutchinson	3,200	175,373	38.0	7.0	9,767	54,990	2,069	162	106,729	1,654	6.19
Hutchinson	3,200	168,375	38.0	7.4	21,038	38,674	2,978	135	104,510	1,092	6.11
Hutchinson	3,224	165,968	38.0	7.5	9,964	50,280	2,569	121	101,093	1,939	6.33
Hutchinson	3,224	168,625	38.0	7.7	10,537	50,277	2,841	108	102,845	2,014	6.36
Hutchinson	3,224	167,658	38.0	5.9	9,155	52,749	1,982	54	101,851	1,864	6.37
Hutchinson	3,226	164,801	38.0	6.7	9,496	50,387	2,525	204	100,268	1,918	6.11
Hutchinson	3,224	173,664	38.0	7.5	10,547	51,871	3,145	135	106,867	1,098	6.27

Table B-1 (cont.)

County	Depth (ft)	TDS (mg/L)	Temp (°C)	Reported pH	Ca (mg/L)	Na (mg/L)	Mg (mg/L)	HCO ₃ (mg/L)	Cl (mg/L)	SO ₄ (mg/L)	pH _c
Hutchinson	3,160	174,055	37.6	7.4	11,527	52,654	2,033	188	106,481	1,169	6.09
Hutchinson	2,960	162,794	36.4	7.5	9,701	50,242	1,980	161	98,991	1,717	6.20
Hutchinson	3,224	166,372	38.0	7.2	9,095	51,183	2,707	157	101,433	1,795	6.24
Hutchinson	3,224	177,774	38.0	8.3	8,112	56,818	2,653	135	108,041	1,946	6.33
Hutchinson	3,224	178,885	38.0	8.5	5,550	61,007	1,960	176	106,027	2,947	6.31
Hutchinson	3,224	144,000	38.0	7.5	3,240	50,200	1,540	378	85,100	3,100	7.50(?)
Hutchinson	3,279	146,000	38.3	7.5	4,000	50,500	1,520	122	87,600	2,050	6.58
Hutchinson	2,978	158,459	36.5	7.0	4,552	54,444	1,661	390	94,501	2,911	6.04
Hutchinson	3,255	149,500	38.2	7.2	6,000	45,400	2,300	261	85,400	1,800	6.25
Hutchinson	3,224	138,000	38.0	8.2	2,500	48,600	1,100	67	81,400	4,100	— (?)
Hutchinson	3,262	130,100	38.2	8.7	2,700	43,700	1,100	55	74,300	3,500	—
Hutchinson	3,250	144,460	38.2	8.8	2,500	47,800	1,000	92	80,100	3,900	6.85
Hutchinson	3,979	144,000	42.6	8.0	2,480	52,000	976	156	84,400	4,000	—
Hutchinson	3,224	149,000	38.0	7.7	3,600	52,400	1,370	293	89,000	2,780	6.35
Hutchinson	3,237	143,000	38.1	7.6	5,880	46,300	2,100	210	86,500	1,850	6.31
Hutchinson	3,220	141,000	38.0	7.1	6,160	45,100	2,210	278	85,500	1,800	6.38
Hutchinson	3,061	180,473	37.0	7.7	8,757	57,563	2,279	100	109,707	1,787	6.44
Hutchinson	3,224	146,846	38.0	7.0	7,453	45,984	2,112	310	89,171	1,781	7.00
Hutchinson	3,061	139,767	37.0	7.0	6,137	45,309	1,764	321	84,335	1,900	6.04
Hutchinson	3,078	159,397	37.1	7.0	6,504	52,459	1,815	297	96,241	2,023	6.04
Hutchinson	3,085	155,587	37.1	7.0	7,694	49,539	1,983	168	94,464	1,736	6.24
Hutchinson	3,224	166,090	38.0	7.0	4,213	58,037	1,524	238	98,954	3,122	6.26
Hutchinson	3,001	163,370	36.6	7.0	5,798	55,275	1,954	0	98,303	2,146	—
Hutchinson	2,990	160,349	36.5	7.0	5,834	55,337	1,556	276	98,517	2,121	6.11
Hutchinson	2,888	162,272	36.0	7.0	3,967	56,885	1,419	657	96,284	3,057	7.00
Hutchinson	3,187	154,448	37.8	7.0	7,047	49,395	2,246	51	93,803	1,903	6.80
Hutchinson	3,213	160,349	37.9	7.0	6,192	52,308	2,139	171	97,423	2,114	6.30
Hutchinson	8,078	144,225	67.7	7.0	5,885	47,466	1,643	269	87,081	1,831	7.00
Hutchinson	2,398	143,000	32.9	7.8	1,860	52,400	820	396	82,300	5,400	6.47
Hutchinson	3,224	142,000	38.0	8.1	1,860	52,100	783	299	81,900	5,300	6.50
Hutchinson	3,297	144,000	38.4	8.3	1,920	52,600	820	293	83,000	5,150	6.56
Hutchinson	3,278	144,000	38.3	8.1	1,920	52,500	820	366	82,600	5,300	6.48
Ochiltree	3,746	188,523	41.2	7.2	6,358	63,785	2,068	171	114,166	1,975	6.26
Carson	3,060	178,000	37.0	7.1	7,850	76,752	2,350	58	89,700	1,290	6.73
Floyd	6,598	240,575	58.6	6.3	6,234	84,667	1,782	132	146,281	1,053	6.26
Floyd	5,800-5,900	111,829	53.7	6.7	5,560	34,600	1,848	581	65,600	3,640	6.70
Hall	3,831	248,006	41.7	6.2	32,340	58,579	2,245	56	153,982	517	6.33
Hansford	3,157	158,971	37.6	7.6	2,304	58,428	860	337	96,251	572	6.30
Hansford	3,240	173,421	38.1	7.3	5,159	60,396	1,188	190	104,484	1,789	6.28
Hansford	3,077	102,260	37.1	7.4	1,114	37,153	573	745	55,685	6,776	6.27
Hansford	3,060	144,322	37.0	7.3	1,794	52,627	729	363	78,721	10,085	6.40
Hemphill	4,365	268,178	45.0	6.7	4,058	99,139	1,177	106	162,710	968	6.53
Roberts	3,550	184,280	40.0	6.5	25,792	22,530	14,160	110	121,360	329	6.25
Roberts	3,552	174,600	40.0	6.9	11,014	51,287	3,406	230	107,666	975	6.02
Roberts	3,538	223,281	39.9	7.8	6,906	76,807	2,098	92	135,338	1,953	6.50
Motley	3,131-3,156	106,286	37.4	6.7	4,927	33,177	1,933	99	63,800	2,350	6.63
Motley	4,200	124,316	44.0	6.6	19,948	22,396	2,940	342	76,735	1,951	6.60
Motley	4,157	129,955	43.7	6.7	22,592	20,561	3,699	264	80,721	2,115	6.70
Sherman	3,007	106,739	36.7	7.1	3,603	35,970	1,124	90	62,426	3,523	6.76
Sherman	3,040	111,715	36.9	6.9	4,209	36,502	1,527	157	65,796	3,428	6.47
Sherman	3,040	93,867	36.9	7.0	3,403	30,849	1,176	77	52,948	5,411	6.85
Sherman	3,032	178,281	36.8	7.4	1,368	66,430	469	127	95,338	14,546	6.95
Sherman	3,032	180,200	36.8	7.8	1,224	66,853	769	254	96,520	14,576	6.70
Sherman	3,032	190,868	36.8	7.3	1,164	71,240	728	231	103,435	14,068	6.76
Sherman	3,032	174,224	36.8	7.5	1,462	42,360	668	184	38,197	13,931	6.80
Sherman	2,997	107,317	36.6	6.7	3,394	35,907	1,457	45	62,862	3,650	6.70

Table B-1 (cont.)

County	Depth (ft)	TDS (mg/L)	Temp (°C)	Reported pH	Ca (mg/L)	Na (mg/L)	Mg (mg/L)	HCO ₃ (mg/L)	Cl (mg/L)	SO ₄ (mg/L)	pH _c
Sherman	3,139	339,529	37.5	6.6	14,686	112,163	3,474	72	208,221	910	6.38
Sherman	2,842	185,592	35.7	8.0	4,787	64,972	1,644	6	111,096	3,085	— (?)
Sherman	2,842	184,650	35.7	5.9	4,683	64,600	1,714	26	110,507	3,117	5.90
Sherman	3,139	194,385	37.5	7.8	2,800	70,116	1,789	149	114,175	5,352	6.62
Sherman	3,046	201,359	36.9	7.0	3,303	73,307	1,232	109	119,305	4,100	6.68
Sherman	3,046	199,027	36.9	6.8	3,965	71,668	1,248	54	118,140	3,949	6.94
Sherman	3,046	208,477	36.9	7.6	3,404	75,747	1,392	112	123,660	4,153	6.66
Sherman	3,046	202,323	36.9	7.3	3,590	73,130	1,386	98	119,939	4,177	6.70
Sherman	3,046	223,712	36.9	7.3	7,818	75,913	2,220	82	135,956	1,721	6.54
Sherman	3,305	210,249	38.5	7.1	7,665	70,951	2,106	47	127,656	1,818	6.78
Sherman	3,305	214,484	38.5	6.5	7,558	72,945	1,972	20	130,164	1,822	6.50
Sherman	3,305	227,980	38.5	7.2	8,038	77,549	2,086	96	138,419	1,789	6.44
Sherman	3,361	235,831	38.8	7.1	9,571	78,096	2,671	96	143,898	1,495	6.40
Sherman	3,361	232,688	38.8	7.0	9,439	76,761	2,887	152	142,044	1,493	6.21
Sherman	3,361	230,970	38.8	6.1	10,262	75,007	2,955	9	141,237	1,502	6.10
Sherman	3,361	340,432	38.8	6.8	1,452	129,734	1,651	46	206,593	935	6.80
Sherman	2,973	134,646	36.5	6.8	3,323	45,176	2,356	124	78,414	5,250	6.68
Sherman	3,084	230,776	37.1	7.1	9,114	76,707	2,609	55	140,782	1,507	6.67
Sherman	3,084	231,294	37.1	6.9	9,284	76,615	2,678	51	141,113	1,550	6.70
Sherman	3,084	231,238	37.1	8.9	6,946	76,352	2,910	41	141,544	1,174	6.89
Sherman	3,469	247,757	39.5	6.2	9,751	77,408	6,016	27	152,662	1,889	6.20
Sherman	3,330	193,111	38.6	7.8	2,820	70,178	1,416	142	113,280	5,272	6.62
Sherman	3,330	198,820	38.6	7.3	2,687	72,117	1,688	95	116,665	1,206	6.81
Sherman	3,330	198,488	38.6	6.3	2,993	70,837	2,238	130	116,966	5,323	6.66
Sherman	3,330	195,470	38.6	7.4	2,688	73,253	1,552	136	114,571	5,502	6.66
Sherman	2,839	198,208	35.6	7.0	14,543	47,828	9,209	38	125,595	995	6.83
Sherman	3,214	167,404	37.9	7.0	1,290	62,286	681	125	92,701	10,321	6.98
Sherman	3,250	145,495	38.2	7.0	1,776	53,592	663	21	82,639	6,804	7.00
Sherman	3,189	167,404	37.8	7.0	1,288	62,293	685	116	92,710	10,312	7.00
Sherman	3,084	232,078	37.1	7.0	9,017	77,633	2,404	55	141,386	1,581	6.67
Lamb	7,352-7,404	173,200	63.1	6.4	15,120	46,607	3,072	195	106,500	1,700	6.40
Crosby	4,363-4,439	105,214	44.9	8.6	6,880	30,143	2,246	139	62,891	2,913	6.35
Crosby	7,650-7,683	230,710	64.8	7.3	8,164	80,271	992	187	140,729	365	7.31
Hockley	8,904-8,990	226,254	73.0	6.9	3,823	83,135	884	333	137,190	588	6.90
Hockley	8,634-8,676	71,811	71.2	6.4	4,687	18,907	2,534	652	42,777	2,252	6.40
Hockley	8,546-8,626	50,595	70.8	7.2	1,840	16,347	488	927	27,300	3,400	7.20
Hockley	9,642-9,648	87,741	77.2	6.6	3,286	29,581	648	801	51,304	2,120	6.60
Motley	2,970-3,022	124,800	36.6	7.5	3,920	46,112	1,972	296	71,050	1,450	—
GRANITE WASH											
County	Depth (ft)	TDS (mg/L)	Temp (°C)	Reported pH	Ca (mg/L)	Na (mg/L)	Mg (mg/L)	HCO ₃ (mg/L)	Cl (mg/L)	SO ₄ (mg/L)	
Hartley	6,140-6,158	189,119	55.8	5.7	9,721	61,511	1,422	41	115,360	1,142	
Oldham	7,122-7,143	219,091	61.8	5.5	9,600	73,490	1,380	61	133,660	960	
Moore	3,465	141,291	39.5	6.6	10,143	41,917	1,487	72	85,259	2,304	
Moore	3,461	143,568	39.5	6.3	10,152	42,725	1,595	13	87,277	1,724	
Moore	3,466-3,472	141,737	40.0	7.9	7,710	36,347	1,105	53	72,000	1,280	

Table B-1 (cont.)

County	Depth (ft)	TDS (mg/L)	Temp (°C)	Reported pH	Ca (mg/L)	Na (mg/L)	Mg (mg/L)	HCO ₃ (mg/L)	Cl (mg/L)	SO ₄ (mg/L)
Moore	3,490	145,330	39.6	7.0	9,067	44,756	1,575	130	89,163	637
Moore	3,851-3,871	138,365	41.8	6.8	10,502	40,876	1,275	66	84,561	1,034
Hutchinson	3,105-3,117	188,045	37.3	7.0	7,847	59,778	2,250	83	112,528	67
Wheeler	6,554-6,569	251,103	58.3	6.4	35,017	56,938	2,138	42	156,025	492
Wheeler	9,148-9,375	208,575	75.2	5.8	15,300	60,253	2,500	116	129,000	176
Wheeler	8,279-8,283	222,672	68.9	5.5	15,000	65,759	2,940	18	138,000	5
Wheeler	8,038-8,044	232,772	67.4	5.5	19,000	65,840	2,240	12	144,000	130
Wheeler	8,308-8,366	254,978	69.1	5.1	16,678	77,789	2,845	8	157,657	0
Wheeler	8,491-8,530	255,653	70.2	4.5	17,355	76,431	3,415	0	158,393	46
Wheeler	7,978-8,018	254,600	67.0	6.4	20,143	73,894	2,818	72	157,657	13
Wheeler	10,985-11,057	—	85.6	5.2	21,400	60,266	2,640	49	143,000	7
Wheeler	7,300	249,657	62.9	5.4	16,678	74,801	3,393	4	154,770	10
Wheeler	7,473	223,986	63.9	5.2	16,718	66,129	2,401	17	138,182	536
Wheeler	8,300	152,922	69.0	5.9	11,725	44,603	1,779	74	94,551	187
Wheeler	7,500	243,131	64.1	5.4	15,160	73,134	3,878	11	150,912	34
Wheeler	7,260-7,385	191,056	63.0	6.2	14,100	55,884	2,490	137	118,000	445
Wheeler	7,904-7,940	211,466	66.7	5.8	14,600	62,038	2,850	110	131,000	48
Wheeler	7,444	251,379	63.8	5.4	16,692	74,647	3,953	13	156,060	11
Wheeler	7,482	226,228	64.0	5.3	18,000	65,246	2,661	11	140,056	252
Wheeler	7,708-7,767	245,021	65.6	5.2	15,883	73,658	3,510	25	151,932	11
Wheeler	7,708-7,767	246,904	65.6	5.1	15,998	74,310	3,487	17	153,083	6
Wheeler	7,475	261,453	64.0	5.3	20,952	75,566	2,868	13	161,796	256
Wheeler	7,453	210,999	63.8	5.1	16,964	60,921	2,302	49	130,410	351
Gray	5,545	232,049	52.2	7.0	4,960	83,454	1,555	183	141,828	69
Gray	5,162-5,178	203,082	49.8	7.3	6,080	71,120	1,361	171	124,100	250
Gray	9,558-9,569	211,932	76.7	7.0	14,945	63,856	2,134	34	130,927	474
Gray	8,808-8,031	214,633	72.1	5.8	13,121	66,093	2,729	49	132,574	65
Gray	2,808-2,987	235,510	35.5	5.3	21,104	64,781	3,122	0	146,408	0
Gray	2,908	224,286	36.1	5.3	17,358	64,097	3,330	13	139,365	0
Gray	2,950	199,804	36.2	4.9	13,171	59,885	2,826	0	123,920	0
Gray	3,000	210,221	36.6	4.4	13,699	70,529	2,407	0	122,819	0
Gray	2,950	201,628	36.3	4.4	12,598	61,952	2,355	0	124,722	0
Gray	3,085	244,775	37.2	7.4	2,195	68,149	2,685	27	151,816	180
Gray	7,720	108,904	65.5	6.6	6,158	34,228	1,339	64	67,562	38
Gray	>7,720	214,044	65.5	5.0	11,920	66,943	2,711	34	132,283	28
Gray	3,215	209,853	37.9	6.1	19,364	55,025	3,015	12	132,434	91
Gray	3,014	223,802	36.7	4.3	19,613	62,027	2,992	0	138,914	255
Gray	3,142	210,995	37.5	5.6	19,436	56,817	3,197	6	130,816	720
Gray	3,110	213,507	37.3	4.0	19,365	57,895	3,197	0	132,436	612
Gray	3,110	192,374	37.3	4.3	18,521	50,588	3,141	0	119,517	605
Gray	3,100	200,182	37.2	6.2	13,761	58,978	3,094	12	124,335	0
Gray	3,080	201,030	37.1	6.6	13,299	60,015	2,963	12	124,738	0
Gray	3,016	199,589	36.7	4.5	13,654	58,997	3,007	0	123,930	0
Gray	3,250	198,769	38.2	5.3	11,561	61,323	2,767	0	123,116	0
Gray	3,077	199,159	37.1	5.2	10,994	62,610	2,432	0	123,122	0
Gray	3,076	193,858	37.1	5.3	12,804	58,055	2,757	0	120,241	0
Gray	2,950	176,163	36.3	4.9	11,613	52,800	2,492	0	109,258	0
Gray	2,950	177,537	36.3	4.4	11,093	54,550	2,074	0	109,820	0
Gray	2,950	170,508	36.3	4.2	16,694	44,735	2,676	0	106,200	203
Gray	3,300	232,174	38.5	5.6	15,206	72,620	1,099	12	141,485	1,437

APPENDIX C:

Determination of Resistivity (Salinity) from Spontaneous Potential Logs

The procedure employed to compute salinity is essentially the same as outlined by Schlumberger (1972). The general formula is

$$SSP = -K \log \frac{R_{mf}}{R_w}$$

where SSP = static spontaneous potential,
read directly from logs

K = coefficient proportional to the
absolute temperature

R_{mf} = resistivity of the mud filtrate

R_w = resistivity of the formation water

A static spontaneous potential (SSP) was determined for every spontaneous potential (SP) log available in the Wolfcamp carbonate and the Permian-Pennsylvanian granite-wash sections (tables C-1 and C-2). The resistivity of the mud, bottom-hole temperature, and measurement temperature are all given as header information on each log chart. Resistivity is converted to the appropriate temperature using the procedure described by Schlumberger (1972) and used in the above equation to compute the resistivity of the formation brine. Finally an equivalent NaCl concentration is determined from the computed resistivity of the formation water.

Such a technique is at best an approximation employed in the absence of actual chemical analyses. Errors may occur in field measurements,

in log interpretation, and in the assumptions inherent in the charts employed. We suspect that the most significant error in these computations results from our assumption that the mud and formation brines are unaffected by the presence of divalent cations, such as calcium and magnesium. Correction factors are available; however, owing to the lack of information concerning the composition of brines and the mud filtrate, it was decided that such corrections were unjustified. The computed values for salinity are all significantly below saturation with respect to halite, and the correction factors have the effect of lowering the estimated salinity values. One concern in the radioactive waste disposal program is whether the brines have the potential to dissolve halite in the overlying evaporite section. Consequently, we have chosen to err on the side of conservatism by converting formation water resistivities to equivalent NaCl solutions. These estimates indicate that the brine is indeed undersaturated, even using this conservative assumption, and would be even more undersaturated if corrections for divalent cations were applied. A tabulation of halite solubility with temperature is given below for comparison (National Research Council, 1928).

Halite		
Temperature	Solubility	
°C	°F	ppm
0	32	262,609
25	77	264,235
50	122	267,856
75	167	273,760
100	212	281,386

Table C-1. Estimates of TDS (salinity) in the Wolfcamp deep-basin aquifer obtained from analysis of spontaneous potential logs.

County, log no.	Interval considered (ft)	SP (mV)	T (°F)	R _{mf} (ohm-m)	R _w (ohm-m)	Estimated TDS (ppm) as NaCl
Armstrong 1	3,500-5,100	90	117	0.5	0.051	100,000
Armstrong 4	3,900-5,100	80	114	0.31	0.046	120,000
Armstrong 16	3,700-4,800	85	104	0.42	0.051	120,000
Briscoe 1	4,600-6,000	115	126	0.45	0.033	160,000
Briscoe 3	4,650-6,000	110	121	0.4	0.034	160,000
Briscoe 6	3,700-4,800	80	104	0.38	0.051	120,000
Briscoe 7	3,400-4,600	80	102	0.4	0.055	110,000
Briscoe 13	4,800-6,100	85	121	0.27	0.039	140,000
Briscoe 16	3,670-4,775	80	112	0.43	0.058	85,000

Table C-1 (cont.)

County, log no.	Interval considered (ft)	SP (mV)	T (°F)	Rmf (ohm-m)	Rw (ohm-m)	Estimated TDS (ppm) as NaCl
Briscoe 18	4,050-5,270	80	115	0.3	0.045	120,000
Carson 6	2,800-3,200	90	101	0.6	0.06	90,000
Castro 2	5,900-7,300	115	137	0.48	0.034	140,000
Castro 3	5,600-7,100	100	124	0.34	0.035	150,000
Castro 6	5,400-6,850	120	133	0.4	0.03	170,000
Castro 16	5,900-7,500	95	128	0.45	0.045	100,000
Childress 5	2,800-4,400	55	110	0.2	0.056	90,000
Childress 6	2,800-4,400	95	103	0.45	0.045	140,000
Childress 12	2,700-4,100	70	105	0.16	0.04	150,000
Childress 16	2,300-3,900	60	105	0.18	0.05	120,000
Childress 30	2,500-4,200	90	105	0.41	0.045	130,000
Childress 32	2,600-4,100	70	100	0.21	0.045	140,000
Childress 39	2,600-4,100	80	97	0.31	0.05	130,000
Childress 41	2,600-4,100	80	96	0.53	0.063	95,000
Childress 47	2,700-4,100	70	96	0.32	0.055	120,000
Childress 59	2,600-4,200	80	106	0.33	0.048	125,000
Childress 61	2,600-4,200	70	106	0.28	0.052	110,000
Childress 63	2,600-4,200	80	105	0.46	0.058	90,000
Childress 66	2,600-4,200	55	103	0.15	0.05	120,000
Childress 68	2,600-4,100	60	106	0.21	0.05	120,000
Childress 70	2,600-4,100	60	99	0.22	0.056	110,000
Cochran 243	2,800-3,600	70	95	0.52	0.078	75,000
Collingsworth 22	2,300-3,600	90	96	0.53	0.051	130,000
Collingsworth 25	2,600-4,000	90	96	0.42	0.047	140,000
Cottle 9	2,800-4,500	90	103	0.4	0.045	140,000
Cottle 10	2,900-4,750	50	101	0.18	0.057	100,000
Cottle 20	2,800-4,750	60	100	0.24	0.057	100,000
Cottle 25	2,800-4,500	90	97	0.3	0.04	170,000
Cottle 29	3,000-4,800	80	106	0.27	0.042	140,000
Cottle 30	2,600-3,800	80	106	0.35	0.051	110,000
Cottle 31	2,600-3,800	70	106	0.33	0.057	95,000
Cottle 34	2,600-3,850	90	106	0.35	0.042	150,000
Cottle 36	2,500-4,300	90	110	0.34	0.042	140,000
Cottle 44	2,300-3,800	70	102	0.2	0.045	140,000
Cottle 45	2,000-3,500	70	98	0.18	0.04	170,000
Cottle 46	2,000-3,500	80	97	0.45	0.057	100,000
Cottle 47	2,100-3,600	110	102	0.45	0.037	180,000
Cottle 70	2,000-3,700	60	94	0.23	0.058	110,000
Cottle 108	2,300-4,100	60	102	0.25	0.058	95,000
Cottle 111	2,300-4,100	70	88	0.34	0.06	120,000
Cottle 115	2,200-4,000	70	99	0.3	0.055	110,000
Cottle 116	2,100-3,600	90	102	0.5	0.051	120,000
Cottle 117	2,000-3,800	80	100	0.4	0.053	115,000
Cottle 118	2,200-3,900	80	90	0.45	0.06	110,000
Cottle 119	2,000-3,500	90	99	0.24	0.037	180,000
Cottle 121	2,700-4,400	70	105	0.28	0.053	100,000
Cottle 129	2,200-3,700	70	99	0.23	0.045	145,000
Cottle 131	2,200-4,000	70	106	0.27	0.05	120,000
Crosby 8	5,600-7,400	60	121	0.21	0.051	90,000
Crosby 9	5,700-7,500	105	98	0.6	0.046	140,000
Crosby 17	5,700-7,500	80	126	0.19	0.035	150,000
Dallam 2	3,300-3,900	80	94	0.75	0.084	70,000
Dallam 15	3,000-3,600	70	82	0.78	0.11	60,000
Dallam 16	3,000-3,600	70	82	0.78	0.11	60,000
Dallam 17	3,000-3,600	70	84	0.62	0.09	70,000

Table C-1 (cont.)

County, log no.	Interval considered (ft)	SP (mV)	T (°F)	Rmf (ohm-m)	Rw (ohm-m)	Estimated TDS (ppm) as NaCl
Dallam 18	3,000-3,600	100	95	0.71	0.053	120,000
Dallam 28	3,000-3,800	90	97	0.76	0.065	90,000
Dallam 36	3,150-4,950	80	96	0.72	0.081	70,000
Dallam 39	3,200-4,900	80	110	0.38	0.05	105,000
Dallam 40	3,700-4,950	90	109	0.52	0.052	100,000
Dallam 41	3,800-5,300	90	104	0.4	0.45	140,000
Dallam 44	3,600-4,700	60	90	0.52	0.1	60,000
Dallam 46	3,400-5,100	100	117	0.5	0.045	120,000
Deaf Smith 5	5,100-6,500	120	121	0.58	0.035	160,000
Deaf Smith 6	5,300-6,700	100	123	0.43	0.04	130,000
Deaf Smith 13	5,700-7,300	110	137	0.42	0.037	130,000
Deaf Smith 14	6,000-7,200	120	139	0.35	0.028	170,000
Deaf Smith 15	5,700-7,000	100	127	0.48	0.041	120,000
Dickens 4	4,300-6,100	50	118	0.12	0.045	120,000
Dickens 8	3,400-5,100	90	105	0.44	0.045	135,000
Dickens 14	4,400-5,700	110	116	0.53	0.038	150,000
Dickens 18	3,800-4,900	70	104	0.34	0.058	95,000
Dickens 21	2,800-4,500	45	105	0.19	0.063	85,000
Dickens 36	3,600-5,600	70	106	0.18	0.041	150,000
Dickens 43	3,700-5,200	100	110	0.29	0.035	170,000
Donley 17	2,900-3,400	110	101	0.4	0.035	190,000
Donley 21	3,000-3,300	110	101	0.5	0.038	180,000
Donley 25	3,000-4,300	105	105	0.4	0.036	180,000
Donley 27	2,900-3,600	80	95	0.31	0.045	150,000
Floyd 2	4,500-6,700	90	113	0.39	0.045	120,000
Floyd 9	5,500-7,500	50	122	0.17	0.057	80,000
Floyd 13	5,200-7,200	65	121	0.18	0.044	110,000
Floyd 29	5,000-7,000	80	116	0.38	0.052	95,000
Gray 3	3,450-4,600	40	113	0.026	0.029	200,000
Gray 7	3,900-4,600	100	116	0.46	0.059	130,000
Gray 12	3,850-4,400	105	120	0.45	0.037	150,000
Gray 14	4,000-4,500	100	116	0.33	0.035	160,000
Gray 18	4,400-5,600	110	127	0.4	0.034	150,000
Gray 25	5,100-6,300	40	109	0.12	0.053	100,000
Gray 28	4,400-5,600	115	128	0.29	0.028	190,000
Gray 31	4,200-5,500	100	125	0.42	0.04	130,000
Gray 32	4,100-5,800	100	112	0.3	0.035	170,000
Gray 33	4,100-5,800	115	112	0.64	0.039	150,000
Gray 41	3,850-5,300	110	116	0.5	0.037	150,000
Gray 43	3,700-5,300	110	115	0.45	0.035	160,000
Gray 44	3,700-5,200	90	122	0.32	0.04	130,000
Gray 47	3,800-5,700	80	115	0.35	0.05	100,000
Gray 48	3,800-5,700	80	113	0.42	0.055	90,000
Hale 33	6,400-7,900	60	138	0.14	0.04	110,000
Hale 42	7,300-9,150	110	134	0.35	0.03	160,000
Hale 56	5,500-7,900	120	137	0.38	0.028	180,000
Hall 1	3,100-5,000	90	95	0.48	0.05	135,000
Hall 13	3,200-4,500	80	111	0.36	0.05	100,000
Hall 18	3,300-5,200	60	102	0.25	0.058	95,000
Hall 20	3,300-4,400	70	107	0.23	0.047	130,000
Hall 22	3,300-4,400	70	103	0.39	0.061	85,000
Hall 23	3,200-4,700	80	105	0.31	0.046	130,000
Hall 19	3,400-4,400	60	99	0.22	0.054	120,000
Hansford 7	3,300-5,000	110	103	0.52	0.039	160,000
Hansford 33	3,400-5,100	90	117	0.2	0.033	180,000
Hansford 35	3,400-5,100	110	116	0.45	0.035	160,000

Table C-1 (cont.)

County, log no.	Interval considered (ft)	SP (mV)	T (°F)	Rmf (ohm-m)	Rw (ohm-m)	Estimated TDS (ppm) as NaCl
Hansford 43	3,400-5,200	100	101	0.6	0.05	120,000
Hansford 44	3,400-5,200	110	103	0.57	0.039	160,000
Hansford 53	3,800-5,300	110	103	0.58	0.04	160,000
Hansford 56	3,800-5,300	100	117	0.35	0.036	160,000
Hansford 58	3,200-5,200	100	115	0.42	0.04	140,000
Hansford 94	3,550-5,000	90	105	0.43	0.047	130,000
Hansford 95	3,500-5,000	90	104	0.39	0.045	140,000
Hansford 101	3,500-5,100	90	99	0.47	0.05	130,000
Hansford 110	3,400-5,100	120	102	0.68	0.038	170,000
Hansford 124	3,400-5,000	90	104	0.35	0.041	150,000
Hansford 138	3,400-5,200	90	104	0.6	0.056	100,000
Hartley 1	3,600-5,100	90	118	0.64	0.06	80,000
Hartley 7	3,600-5,600	100	108	0.58	0.045	130,000
Hartley 12	3,500-5,400	100	113	0.42	0.039	145,000
Hartley 13	3,400-5,400	100	116	0.46	0.041	140,000
Hartley 17	3,600-5,800	115	122	0.43	0.033	160,000
Hartley 20	3,700-5,450	80	113	0.47	0.059	85,000
Hartley 21	3,600-5,200	90	97	0.57	0.055	120,000
Hartley 24	4,100-6,000	110	121	0.46	0.035	160,000
Hartley 28	3,900-5,500	110	125	0.55	0.039	135,000
Hartley 33	4,100-6,300	115	103	0.6	0.038	170,000
Hartley 34	4,100-6,300	110	126	0.37	0.032	170,000
Hartley 35	4,000-6,200	100	128	0.53	0.046	100,000
Hartley 38	3,750-5,400	100	108	0.45	0.037	160,000
Hartley 40	4,000-5,900	120	125	0.36	0.029	190,000
Hartley 41	4,000-5,500	110	118	0.46	0.035	160,000
Hartley 42	3,700-5,300	125	121	0.4	0.029	190,000
Hartley 44	3,900-5,600	100	109	0.5	0.042	140,000
Hartley 51	3,900-5,800	70	115	0.32	0.056	85,000
Hartley 95	3,800-5,900	40	117	0.028	0.028	225,000
Hartley 97	3,800-5,900	130	120	0.53	0.03	190,000
Hemphill 2	3,800-5,400	40	120	0.095	0.045	120,000
Hemphill 8	4,000-6,000	80	115	0.21	0.037	160,000
Hemphill 9	4,100-5,800	50	118	0.12	0.045	120,000
Hemphill 10	3,900-5,200	110	109	0.49	0.038	160,000
Hemphill 11	3,800-5,200	115	108	0.5	0.035	180,000
Hemphill 20	4,000-5,900	120	113	0.55	0.034	170,000
Hemphill 21	4,000-5,800	60	116	0.14	0.042	130,000
Hemphill 31	4,300-6,000	110	113	0.53	0.038	150,000
Hemphill 32	4,000-6,000	110	113	0.49	0.036	160,000
Hemphill 34	4,300-6,400	110	113	0.15	0.024	300,000+
Hemphill 38	4,300-6,000	110	131	0.33	0.03	170,000
Hemphill 41	4,400-6,200	100	115	0.55	0.045	120,000
Hemphill 42	4,500-6,100	110	117	0.4	0.035	160,000
Hemphill 44	4,500-6,200	110	115	0.57	0.04	140,000
Hockley 9	7,500-8,800	80	110	0.4	0.055	95,000
Hockley 199	7,200-8,500	130	151	0.34	0.024	190,000
Hockley 202	7,500-8,700	130	164	0.2	0.019	250,000
Hockley 204	7,300-9,400	100	163	0.32	0.033	120,000
Hockley 236	7,800-9,200	80	148	0.4	0.055	70,000
Hockley 469	7,700-9,100	80	147	0.34	0.05	75,000
Hockley 474	7,200-9,100	110	158	0.22	0.024	180,000
Hockley 498	4,500-5,000	110	114	0.66	0.043	130,000
Hutchinson 10	3,300-4,800	120	113	0.49	0.031	180,000
Hutchinson 11	3,400-4,800	90	109	0.25	0.035	180,000
Hutchinson 13	3,400-4,800	80	109	0.46	0.058	90,000

Table C-1 (cont.)

County, log no.	Interval considered (ft)	SP (mV)	T (°F)	Rmf (ohm-m)	Rw (ohm-m)	Estimated TDS (ppm) as NaCl
Hutchinson 16	3,300-4,400	110	111	0.32	0.031	200,000
Hutchinson 18	3,300-4,500	110	111	0.41	0.035	170,000
Hutchinson 23	3,300-5,100	110	111	0.44	0.036	160,000
Hutchinson 28	3,500-5,000	110	111	0.62	0.04	140,000
Hutchinson 33	3,300-4,800	120	108	0.57	0.035	160,000
Hutchinson 62	3,300-5,100	120	110	0.55	0.035	180,000
Lipscomb 4	3,300-4,700	110	102	0.69	0.05	120,000
Lipscomb 8	3,300-4,900	110	105	0.52	0.044	135,000
Lipscomb 31	3,400-5,000	100	106	0.39	0.04	155,000
Lipscomb 43	3,500-5,000	110	110	0.46	0.038	150,000
Lipscomb 47	3,700-5,200	80	106	0.35	0.055	95,000
Lipscomb 48	3,800-5,700	110	115	0.4	0.037	150,000
Lipscomb 49	3,900-5,900	90	116	0.26	0.041	130,000
Lipscomb 53	3,700-5,200	110	114	0.44	0.036	155,000
Lipscomb 58	3,800-5,400	110	115	0.38	0.032	180,000
Lipscomb 59	4,000-5,500	115	113	0.43	0.032	185,000
Lubbock 41	4,100-6,000	110	107	0.41	0.038	160,000
Moore 14	2,800-5,100	105	119	0.55	0.038	140,000
Moore 16	3,700-4,100	110	108	0.54	0.039	150,000
Moore 17	3,600-5,100	120	107	0.61	0.034	180,000
Moore 34	3,200-4,200	130	115	0.6	0.039	140,000
Moore 10	2,800-3,600	50	98	0.35	0.075	70,000
Moore 28	2,500-3,400	100	104	0.58	0.05	115,000
Moore 49	2,900-3,500	60	97	0.18	0.055	110,000
Motley 4	3,400-5,300	80	112	0.41	0.052	95,000
Motley 6	3,000-4,800	80	109	0.34	0.051	100,000
Motley 10	4,300-6,600	110	121	0.36	0.03	185,000
Motley 39	3,700-5,400	100	126	0.36	0.04	125,000
Ochiltree 16	3,300-4,600	110	107	0.43	0.039	150,000
Ochiltree 25	3,300-4,500	100	98	0.52	0.048	130,000
Ochiltree 28	3,400-5,100	110	109	0.53	0.038	155,000
Ochiltree 29	3,500-4,800	115	111	0.44	0.032	185,000
Ochiltree 44	3,700-5,000	110	114	0.42	0.032	180,000
Ochiltree 47	3,600-4,800	130	106	0.51	0.03	220,000
Oldham 8	4,500-7,000	120	108	0.46	0.036	165,000
Oldham 21	3,900-5,400	90	113	0.34	0.045	115,000
Oldham 27	2,900-3,200	90	97	0.44	0.057	100,000
Oldham 24	3,300-5,100	100	102	0.6	0.048	125,000
Oldham 42	4,500-6,600	115	113	0.55	0.04	140,000
Oldham 59	4,500-4,900	90	109	0.52	0.056	90,000
Oldham 62	4,900-5,300	70	116	0.36	0.061	75,000
Oldham 71	4,800-6,500	110	116	0.53	0.042	130,000
Parmer 1	6,400-7,800	90	132	0.28	0.037	125,000
Parmer 9	6,700-7,600	130	135	0.56	0.026	200,000
Potter 14	4,000-5,500	90	105	0.25	0.038	160,000
Potter 34	4,100-5,800	80	107	0.48	0.056	90,000
Potter 43	4,900-6,300	120	115	0.45	0.03	200,000
Randall 15	4,700-6,600	110	121	0.6	0.04	130,000
Roberts 4	3,300-4,800	60	114	0.065	0.034	175,000
Roberts 6	3,400-4,800	100	110	0.32	0.038	150,000
Roberts 17	3,600-5,000	120	116	0.37	0.03	200,000
Roberts 25	3,600-4,800	120	116	0.54	0.031	185,000
Roberts 27	3,800-5,100	140	118	0.41	0.028	225,000

Table C-1 (cont.)

County, log no.	Interval considered (ft)	SP (mV)	T (°F)	Rmf (ohm-m)	Rw (ohm-m)	Estimated TDS (ppm) as NaCl
Roberts 29	4,200-5,700	110	123	0.31	0.028	190,000
Roberts 32	4,300-5,700	120	123	0.37	0.027	200,000
Roberts 44	4,200-6,100	90	111	0.36	0.035	170,000
Sherman 1	3,400-4,700	60	82	0.57	0.08	80,000
Sherman 4	2,500-3,300	80	80	0.65	0.065	110,000
Sherman 16	3,000-4,400	60	82	0.79	0.09	70,000
Sherman 35	3,000-4,300	100	108	0.42	0.044	130,000
Sherman 46	2,800-4,200	90	103	0.27	0.045	135,000
Sherman 47	2,600-4,700	95	98	0.33	0.038	180,000
Sherman 49	3,200-4,500	100	109	0.44	0.04	145,000
Sherman 52	3,400-5,000	100	102	0.31	0.036	180,000
Sherman 60	3,300-4,600	90	106	0.28	0.04	150,000
Swisher 4	5,300-6,600	110	120	0.58	0.038	140,000
Swisher 6	5,300-6,500	70	124	0.34	0.043	110,000
Wheeler 6	4,600-6,000	110	117	0.33	0.03	190,000
Wheeler 31	4,100-5,900	100	119	0.33	0.034	160,000
Wheeler 35	4,200-6,200	100	119	0.29	0.037	170,000
Wheeler 37	4,300-6,200	100	129	0.5	0.037	130,000
Wheeler 51	4,500-6,000	90	121	0.33	0.035	150,000
Wheeler 54	4,200-6,500	110	119	0.75	0.042	125,000
Wheeler 55	4,300-6,500	110	118	0.38	0.031	180,000
Wheeler 57	4,600-6,600	110	121	0.7	0.042	120,000
Wheeler 58	4,300-6,500	105	129	0.45	0.032	155,000
Wheeler 69	3,300-6,000	90	125	0.45	0.038	130,000
Wheeler 81	4,400-6,500	120	130	0.42	0.027	190,000

Table C-2. Estimates of TDS (salinity) in the granite-wash deep-basin aquifer obtained from analysis of spontaneous potential logs.

County, log no.	Interval considered (ft)	SP (mV)	T (°F)	Rmf (ohm-m)	Rw (ohm-m)	Estimated TDS (ppm) as NaCl
Armstrong 8	4,600	125	111	0.26	0.031	200,000
Armstrong 16	5,340-5,360	98	119	0.38	0.034	160,000
Armstrong 21	5,700	95	123	0.6	0.049	90,000
Briscoe 6	5,870-5,895	103	125	0.3	0.031	170,000
Briscoe 7	5,650-5,660	95	122	0.33	0.035	150,000
Briscoe 13	7,720-7,740	93	145	0.24	0.03	150,000
Carson 46	5,400	105	119	0.52	0.04	130,000
Castro 4	7,920-7,950	70	147	0.17	0.039	100,000
Castro 6	8,490-8,505	115	153	0.32	0.027	160,000
Castro 9	8,610-8,625	110	155	0.33	0.027	160,000
Castro 16	8,930-8,980	120	159	0.34	0.025	170,000
Castro 3	7,840-7,890	92	147	0.3	0.039	100,000
Childress 8	5,090-5,110	80	116	0.29	0.045	120,000
Childress 10	5,115-5,160	55	117	0.14	0.045	120,000
Childress 11	5,380-5,420	75	119	0.23	0.043	120,000
Childress 17	5,790-5,820	95	124	0.31	0.036	140,000
Childress 28	6,090-6,110	80	127	0.31	0.045	100,000
Childress 30	6,650-6,680	110	133	0.31	0.03	160,000
Childress 39	6,380-6,400	80	130	0.23	0.04	120,000

Table C-2 (cont.)

County, log no.	Interval considered (ft)	SP (mV)	T (°F)	Rmf (ohm-m)	Rw (ohm-m)	Estimated TDS (ppm) as NaCl
Childress 44	6,490-6,530	65	132	0.15	0.039	120,000
Childress 46	6,605-6,630	60	133	0.15	0.043	100,000
Childress 47	6,315-6,335	70	130	0.24	0.044	100,000
Childress 52	4,590-4,640	65	111	0.22	0.051	100,000
Collingsworth 2	9,170-9,190	110	161	0.39	0.041	85,000
Collingsworth 25	4,900-4,930	73	114	0.35	0.062	75,000
Cottle 6	6,220-6,250	60	129	0.15	0.038	130,000
Cottle 9	6,760-6,820	97	135	0.3	0.034	140,000
Cottle 18	4,480-4,500	65	109	0.2	0.047	120,000
Cottle 20	6,690-6,720	75	134	0.18	0.036	130,000
Cottle 25	5,150-5,165	65	117	0.26	0.052	90,000
Cottle 26	4,570-4,590	105	110	0.43	0.039	150,000
Cottle 33	5,735-5,775	77	123	0.18	0.035	150,000
Cottle 34	5,670-5,700	95	123	0.3	0.035	150,000
Cottle 41	6,420-6,500	80	131	0.15	0.032	150,000
Dallam 5	4,970-4,990	105	115	0.57	0.04	140,000
Dallam 20	6,500	100	132	0.53	0.045	95,000
Dallam 22	4,735-4,770	100	112	0.53	0.042	130,000
Dallam 29	4,900	120	114	0.63	0.037	150,000
Dallam 33	5,970-5,995	130	126	0.55	0.028	190,000
Dallam 36	5,430-5,455	130	120	0.6	0.03	180,000
Dallam 39	6,180-6,195	90	128	0.31	0.038	130,000
Dallam 40	6,390-6,415	84	130	0.41	0.04	120,000
Dallam 43	6,500-6,550	135	132	0.49	0.027	190,000
Dallam 44	5,410-5,460	100	120	0.4	0.036	150,000
Dallam 46	6,820-6,845	140	135	0.44	0.026	200,000
Deaf Smith 13	8,605-8,635	120	160	0.35	0.024	170,000
Deaf Smith 15	8,820-8,840	115	162	0.36	0.026	160,000
Dickens 3	7,925-7,950	70	147	0.2	0.039	100,000
Dickens 11	6,370-6,380	95	130	0.42	0.04	120,000
Dickens 31	6,770-6,820	110	135	0.33	0.03	160,000
Donley 3	4,200	70	106	0.3	0.056	95,000
Donley 21	3,945-3,960	100	108	0.45	0.047	120,000
Donley 24	5,700	120	123	0.52	0.035	150,000
Donley 25	5,375-5,410	110	119	0.36	0.036	150,000
Donley 26	5,410-5,430	90	120	0.33	0.045	110,000
Donley 27	4,380-4,395	60	108	0.26	0.042	140,000
Donley 28	5,110-5,115	75	116	0.24	0.041	130,000
Donley 29	3,400	70	98	0.4	0.062	90,000
Donley 31	5,125-5,145	90	116	0.4	0.045	120,000
Donley 32	4,825-4,840	110	113	0.57	0.04	140,000
Donley 36	5,125-5,140	90	116	0.3	0.036	150,000
Donley 38	5,425-5,440	80	120	0.18	0.034	160,000
Floyd 3	6,220-6,270	115	129	0.43	0.03	170,000
Floyd 8	9,200	40	161	0.034	0.025	170,000
Gray 3	7,500-7,540	40	148	0.095	0.022	250,000
Gray 7	7,630-7,710	133	149	0.35	0.022	250,000
Gray 8	7,830-7,860	95	151	0.2	0.026	170,000
Gray 9	6,600-6,670	110	138	0.33	0.028	170,000
Gray 11	6,800-6,900	100	140	0.23	0.028	170,000
Gray 14	7,610-7,670	100	149	0.25	0.028	160,000
Gray 15	6,400-6,440	130	136	0.4	0.029	170,000
Gray 18	7,560-7,630	120	149	0.33	0.026	170,000
Gray 19	8,010-8,050	110	153	0.5	0.027	160,000

Table C-2 (cont.)

County, log no.	Interval considered (ft)	SP (mV)	T (°F)	Rmf (ohm-m)	Rw (ohm-m)	Estimated TDS (ppm) as NaCl
Gray 21	8,475-8,500	160	158	0.58	0.025	170,000
Gray 27	6,700-6,770	120	139	0.41	0.025	200,000
Gray 28	8,160-8,230	135	155	0.24	0.019	300,000
Gray 31	6,480-6,650	120	137	0.4	0.027	180,000
Gray 46	8,370-8,430	100	157	0.39	0.029	140,000
Gray 23	6,260-6,320	95	129	0.26	0.03	170,000
Gray 33	8,900-8,990	140	158	0.45	0.022	200,000
Gray 41	6,520-6,670	130	133	0.42	0.027	190,000
Hall 1	4,900-4,945	90	114	0.39	0.045	120,000
Hall 13	6,045-6,075	110	127	0.31	0.034	150,000
Hall 23	6,440-6,490	90	131	0.24	0.034	140,000
Hall 22	5,040-5,120	100	116	0.34	0.039	140,000
Hansford 26	6,190-6,200	97	128	0.35	0.036	140,000
Hansford 33	5,160-5,175	90	117	0.2	0.038	140,000
Hansford 35	5,050-5,090	110	116	0.45	0.038	140,000
Hansford 38	6,095-6,110	110	127	0.28	0.029	180,000
Hansford 48	5,230-5,260	100	118	0.47	0.04	130,000
Hansford 52	4,910-4,980	120	114	0.58	0.036	160,000
Hansford 58	5,500-5,510	100	121	0.4	0.038	140,000
Hansford 59	5,465-5,480	90	120	0.29	0.038	140,000
Hansford 84	4,800-4,910	120	113	0.58	0.036	160,000
Hansford 85	5,010-5,020	115	115	0.55	0.039	140,000
Hansford 86	5,155-5,200	110	117	0.56	0.038	140,000
Hansford 93	5,260-5,310	82	118	0.33	0.043	120,000
Hansford 94	5,200-5,250	100	117	0.38	0.036	150,000
Hansford 103	5,120-5,180	105	117	0.4	0.035	160,000
Hansford 104	5,140-5,210	105	117	0.45	0.039	140,000
Hansford 105	5,175-5,260	100	117	0.26	0.033	170,000
Hansford 108	4,765-4,790	100	113	0.4	0.038	150,000
Hansford 122	4,850-4,870	90	113	0.27	0.038	150,000
Hansford 124	4,930-4,980	90	115	0.31	0.04	140,000
Hansford 110	5,280-5,310	120	118	0.58	0.035	160,000
Hansford 118	5,780-5,800	100	124	0.32	0.039	130,000
Hansford 119	4,750-4,775	117	112	0.52	0.034	170,000
Hansford 133	5,375-5,450	100	120	0.29	0.034	160,000
Hansford 138	5,080-5,110	100	116	0.5	0.045	120,000
Hartley 1	6,470-6,480	115	136	0.6	0.032	150,000
Hartley 2	6,110-6,190	110	133	0.6	0.027	190,000
Hartley 7	7,370-7,400	100	146	0.42	0.04	100,000
Hartley 10	6,500	100	132	0.34	0.033	150,000
Hartley 16	6,610-6,670	120	138	0.37	0.028	170,000
Hartley 17	6,580-6,690	120	138	0.4	0.028	170,000
Hartley 23	6,450-6,570	120	137	0.45	0.028	170,000
Hartley 24	6,780-6,830	115	132	0.41	0.031	160,000
Hartley 25	6,310-6,550	110	136	0.35	0.034	140,000
Hartley 26	6,430-6,680	110	136	0.4	0.031	160,000
Hartley 33	6,400	130	130	0.35	0.027	200,000
Hartley 34	7,660-7,740	120	149	0.55	0.031	140,000
Hartley 37	6,500-6,580	115	132	0.36	0.028	180,000
Hartley 39	6,870-6,900	100	138	0.45	0.028	170,000
Hartley 61	7,540-7,580	107	148	0.37	0.029	150,000
Hartley 85	5,900	85	125	0.29	0.041	120,000
Hartley 86	5,960-6,000	80	131	0.44	0.044	100,000
Hartley 89	6,100	100	127	0.34	0.041	120,000

Table C-2 (cont.)

County, log no.	Interval considered (ft)	SP (mV)	T (°F)	Rmf (ohm-m)	Rw (ohm-m)	Estimated TDS (ppm) as NaCl
Hemphill 11	5,500	125	121	0.44	0.031	180,000
Hemphill 32	5,900	120	125	0.42	0.031	170,000
Hemphill 42	9,600	135	166	0.28	0.021	200,000
Hemphill 43	10,000	150	170	0.41	0.021	200,000
Hutchinson 1	5,380-5,400	120	124	0.48	0.036	140,000
Hutchinson 4	5,170-5,210	80	122	0.45	0.042	120,000
Hutchinson 10	5,470-5,490	110	125	0.45	0.03	180,000
Hutchinson 11	5,450-5,470	80	125	0.23	0.036	140,000
Hutchinson 13	6,560-6,580	80	137	0.22	0.036	130,000
Hutchinson 15	6,440-6,470	75	136	0.18	0.034	140,000
Hutchinson 16	6,300-6,320	105	134	0.27	0.029	170,000
Hutchinson 17	6,500	90	132	0.28	0.036	130,000
Hutchinson 18	6,180-6,300	115	134	0.34	0.028	180,000
Hutchinson 19	6,100	110	127	0.36	0.03	170,000
Hutchinson 23	6,180-6,420	120	134	0.35	0.03	160,000
Hutchinson 25	5,490-6,040	130	128	0.51	0.036	140,000
Hutchinson 28	6,320-6,450	160	135	0.51	0.026	190,000
Hutchinson 29	6,360-6,370	115	135	0.4	0.028	170,000
Hutchinson 30	5,190-5,230	110	122	0.43	0.037	140,000
Hutchinson 31	5,340-5,360	90	124	0.26	0.034	150,000
Hutchinson 32	5,950-6,020	100	131	0.34	0.03	170,000
Hutchinson 33	6,880-6,920	120	141	0.45	0.028	170,000
Hutchinson 40	5,910-5,960	45	131	0.09	0.04	120,000
Hutchinson 60	5,750-5,780	100	128	0.41	0.036	140,000
Hutchinson 62	6,210-6,310	115	134	0.45	0.029	170,000
King 41	5,160-5,190	98	117	0.35	0.036	150,000
Lipscomb 4	5,780-5,800	120	124	0.54	0.033	160,000
Lipscomb 11	5,930-6,000	80	126	0.18	0.034	150,000
Lipscomb 25	6,580-6,600	105	132	0.36	0.034	140,000
Lipscomb 31	6,140-6,330	105	129	0.32	0.032	160,000
Lipscomb 33	6,240-6,330	120	129	0.39	0.029	180,000
Lipscomb 44	6,330-6,450	130	130	0.45	0.028	180,000
Lipscomb 46	6,390-6,460	103	131	0.34	0.032	150,000
Lipscomb 50	6,435-6,530	90	131	0.23	0.032	150,000
Lipscomb 53	6,330-6,440	110	130	0.35	0.031	160,000
Lipscomb 58	6,770-6,820	120	135	0.32	0.028	180,000
Moore 14	5,320-5,330	110	124	0.5	0.034	150,000
Moore 17	5,850-5,880	130	130	0.51	0.028	180,000
Moore 20	6,250-6,280	130	129	0.6	0.028	180,000
Moore 28	5,580-5,630	95	122	0.48	0.037	140,000
Moore 34	5,835-5,860	105	124	0.45	0.028	200,000
Motley 3	7,185-7,210	105	139	0.33	0.027	180,000
Motley 4	7,400-7,415	100	141	0.32	0.032	140,000
Motley 5	7,170-7,215	105	139	0.35	0.033	140,000
Motley 7	7,645-7,670	83	144	0.22	0.034	130,000
Ochiltree 9	6,080-6,100	128	127	0.51	0.029	180,000
Ochiltree 24	5,730-5,750	67	123	0.13	0.034	150,000
Ochiltree 25	5,710-5,750	92	123	0.4	0.042	120,000
Ochiltree 26	5,810-5,840	78	124	0.2	0.036	140,000
Ochiltree 28	5,980-6,000	110	126	0.45	0.034	150,000
Ochiltree 29	5,970-6,030	110	126	0.4	0.032	160,000
Ochiltree 31	5,690-5,830	120	123	0.5	0.033	160,000
Ochiltree 42	5,775-5,910	130	124	0.35	0.028	200,000
Ochiltree 44	6,210-6,300	120	129	0.36	0.028	180,000
Ochiltree 45	6,220-6,390	120	129	0.4	0.029	180,000

Table C-2 (cont.)

County, log no.	Interval considered (ft)	SP (mV)	T (°F)	Rmf (ohm-m)	Rw (ohm-m)	Estimated TDS (ppm) as NaCl
Ochiltree 46	6,350-6,440	120	130	0.43	0.03	170,000
Ochiltree 47	6,000-6,100	125	127	0.43	0.029	180,000
Ochiltree 49	5,780-5,930	120	124	0.53	0.033	160,000
Ochiltree 55	6,085-6,180	100	127	0.3	0.032	160,000
Ochiltree 56	6,280-6,360	120	130	0.4	0.028	180,000
Ochiltree 59	6,335-6,460	120	130	0.43	0.03	170,000
Oldham 8	6,800	125	135	0.36	0.036	130,000
Oldham 24	5,480-5,510	100	125	0.47	0.042	120,000
Oldham 36	6,280-6,370	120	130	0.34	0.027	200,000
Oldham 49	7,560-7,620	95	143	0.27	0.03	150,000
Parmer 1	8,570-8,750	95	155	0.24	0.028	150,000
Parmer 9	8,450-8,490	120	153	0.45	0.028	150,000
Potter 12	6,370-6,420	70	128	0.29	0.06	70,000
Potter 14	5,710-5,720	70	123	0.21	0.046	100,000
Potter 27	5,500	100	125	0.46	0.041	120,000
Potter 43	6,925-6,940	115	141	0.35	0.027	180,000
Randall 13	7,505-7,525	135	148	0.35	0.024	200,000
Randall 14	7,200	130	139	0.47	0.027	180,000
Randall 22	8,200	110	150	0.26	0.025	180,000
Randall 23	7,705-7,770	115	150	0.25	0.025	180,000
Roberts 1	5,300-5,500	65	126	0.13	0.036	140,000
Roberts 5	6,050-6,170	110	132	0.44	0.033	150,000
Roberts 6	6,090-6,120	110	132	0.27	0.028	180,000
Roberts 11	6,400-6,450	90	136	0.36	0.034	140,000
Roberts 25	7,500-7,560	120	148	0.4	0.025	180,000
Roberts 27	6,010-6,040	150	131	0.25	0.022	300,000+
Roberts 32	8,670-8,690	110	160	0.27	0.025	170,000
Roberts 34	8,380-8,450	120	158	0.32	0.024	180,000
Roberts 38	8,570-8,710	120	160	0.24	0.024	180,000
Sherman 1	4,675-4,725	100	112	0.41	0.036	160,000
Sherman 4	4,920-4,930	120	114	0.45	0.032	180,000
Sherman 8	5,995-6,020	102	126	0.39	0.035	150,000
Sherman 14	5,790-5,805	110	124	0.24	0.028	200,000
Sherman 16	4,400	110	108	0.59	0.032	200,000
Sherman 17	4,220-4,270	140	107	0.65	0.03	240,000
Sherman 26	4,380-4,430	130	108	0.49	0.034	180,000
Sherman 27	4,600	90	111	0.26	0.037	160,000
Sherman 49	5,820-5,840	105	124	0.36	0.031	170,000
Sherman 50	5,200	115	117	0.36	0.032	180,000
Sherman 59	6,000	120	126	0.39	0.027	200,000
Swisher 3	7,580-7,600	120	148	0.27	0.024	190,000
Swisher 4	8,425-8,450	125	153	0.42	0.026	170,000
Wheeler 1	8,730-8,780	160	161	0.4	0.018	300,000
Wheeler 2	7,900-7,970	155	152	0.62	0.022	220,000
Wheeler 4	9,200	130	161	0.32	0.021	220,000
Wheeler 17	9,100	140	160	0.39	0.022	200,000
Wheeler 20	8,900	130	158	0.43	0.024	180,000
Wheeler 23	9,985-10,020	108	175	0.12	0.017	280,000
Wheeler 31	8,300	100	151	0.25	0.028	150,000
Wheeler 35	6,390-6,430	90	136	0.25	0.034	140,000
Wheeler 40	6,900	125	136	0.5	0.03	160,000
Wheeler 41	6,300	115	129	0.5	0.034	150,000
Wheeler 45	6,900	105	136	0.46	0.033	140,000
Wheeler 54	5,700-5,730	120	128	0.68	0.038	130,000
Wheeler 55	7,450-7,490	110	147	0.3	0.026	180,000